TECHNICAL FEASIBILITY AND LIFE CYCLE COST ASSESSMENT OF A PHOTOVOLTAIC ARRAY ON TRINITY DAM, TRINITY COUNTY, CA

By

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ABSTRACT

TECHNICAL FEASIBILITY AND LIFE CYCLE COST ASSESSMENT OF A PHOTOVOLTAIC ARRAY ON TRINITY DAM, TRINITY COUNTY, CA

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Public lands owned by the Bureau of Land Management are increasingly being used for photovoltaic (PV) system development. Although numerous policies support PV deployment on public lands, those managed by the Bureau of Reclamation have not been considered for PV development. Hydro-electric embankment dams, both publicly and privately owned, may have the potential to be development sites for distributed PV systems. A technical feasibility report was conducted for a case study of a PV installation on Trinity Dam, Trinity County, CA, and found embankment dams could potentially be feasible development sites. A mounting analysis found that a concrete slab reinforced with rebar could be used to mount a PV array on Trinity Dam. A nominal 1 MW-dc PV system was designed and used to determine lifetime system production and to conduct the economic analysis. The hypothetical system at the Trinity Dam site is estimated to have a lifetime energy production of approximately 30 GWh and would displace about 8,000 metric tons of CO_2-equivalent. Non-profit and private ownership scenarios were considered to estimate the economic feasibility of a 1MW-dc distributed PV system on Trinity Dam. System costs and benefits were calculated and analyzed for a 25-year investment. A life cycle cost assessment found that a non-profit system connected behind the meter for on-site consumption would have a levelized cost of energy of $0.056/kWh,

a discounted payback period of 8.7 years, and an internal rate of return of 9%. A privately owned system would produce a levelized cost of energy of $0.04/kWh, a discounted payback period of 4.9 years, and an internal rate of return of 16%. Based on the LCCA for a 1 MW-dc system on Trinity Dam, it is recommended that a non-profit or private investment could be economically beneficial if the system was installed behind the meter to serve on-site loads under the PG&E E-19 rate tariff. In a front of the meter PPA contract scenario, a non-profit investment would have a DPB of more than 25 years and a private investment would have a DPB of 16.2 years. Therefore, an investment in a front of the meter system for Trinity Dam is not recommended unless a higher PPA rate can be negotiated with the utility.

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LIST OF ACRONYMS

BIPV	Building Integrated Photovoltaics
BLM	Bureau of Land Management
BOR	Bureau of Reclamation
BTM	Behind the meter
CPV	Concentrating Photovoltaic(s)
c-Si	Crystalline Silicone
DG	Distributed Generation
DOE	Department of Energy
DOI	Department of Interior
DPB	Discounted Payback (Period)
EPAct	Energy Policy Act of 2005
EUL	Enhanced Use Lease
FEMP	Federal Energy Management Program
FTM	Front of the meter
GW	Gigawatt
IRR	Internal Rate of Return
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-hour
LCCA	Life Cycle Cost Assessment
LDPV	Locally Distributed Photovoltaic(s)
LGF	Large Generating Facility
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
MACRS	Modified Accelerated Cost Recovery System
MARR	Minimum Acceptable Rate of Return
MW	Megawatt
MW-ac	Megawatt alternating current rating
MW-dc	Megawatt direct current rating
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
N-HRE	Non-Hydro Renewable Energy
NOL	Notice of Opportunity to Lease
OATT	Open Access Transmission Service Tariff
PII	Permitting, Inspection and Interconnection
PPA	Power Purchasing Agreement
PV	Photovoltaic(s)
REC	Renewable Energy Certificate
ROD	Record of Decision

SGIP	Self-Generation Incentive Program
SGF	Small Generating Facility
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SIS	System Impact Study
SOW	Scope of Work
SREC	Solar Renewable Energy Certificate
WAPA	Western Area Power Administration

INTRODUCTION

Solar photovoltaic (PV) energy systems produce energy from sunlight in numerous applications. PV technology has historically been used to provide off-grid electricity and as a supplemental energy source for grid-connected customers. Recently PV has been used for large power plant facilities, which produce electricity fed onto a high voltage transmission grid through utility interconnection (Dunlop, 2010). Utility scale PV system development has grown in recent years. As of September 2017, more than 20,500 megawatts (MW) of solar projects were in operation in the United States (Solar Energy Industries Association, 2017). There are also more than 49,000 MW of PV and concentrated solar power (CSP) projects currently under construction or development (Solar Energy Industries Association, 2017).

Federal agencies have recently been motivated to deploy renewable energy on their public lands by several pieces of legislation. Renewable energy development has only been approved on Department of Interior (DOI) lands managed by the Bureau of Land Management (BLM). This technical and economic feasibility study proposes that Bureau of Reclamation (BOR) lands also be considered for renewable energy generation, specifically PV system deployment on earth and rock-fill dams.

There are 84,134 dams in the United States, and 74,119 of them are earth and rock-fill dams (National Inventory of Dams, 2012). Roughly 30% of all dams are publicly owned by federal, state, and local governments and public utilities, and 2,210 of

these dams are used for hydroelectric purposes (National Inventory of Dams, 2012). Most dams are less than 50 feet in height, but 6,294 are more than 50 feet (National Inventory of Dams, 2012). The larger the dam surface is, the larger a distributed PV system it could potentially support.

Photovoltaic systems have not yet been considered for installation on dams. There may be several benefits from using dam sites for PV: the surfaces are man-made, and thus the footprint of a large PV installation on these sites may result in less environmental impact than on undeveloped surfaces; hydroelectric dams have electrical transmission infrastructure on site, including transmission lines that may be able to carry additional energy produced by a PV system; dam sites are protected and maintained consistently, ensuring the safety of a PV installation; and dams owned and managed by the BOR could be affected by inclusion into programs that have stimulated renewable energy development on BLM lands. The combination of these attributes could represent numerous avoided costs typically associated with the deployment of large PV systems.

The background section of the report provides information on PV technology, earth and rock-fill embankment dams, the history of PV development on federal lands, financing of PV systems and the potential for their deployment on embankment dams.

The case study section estimates the potential of hydro-electric embankment dams as sites for PV development, and uses Trinity Dam, in Trinity County, California, as an example. A technical feasibility study analyzes the engineering and regulatory restrictions associated with a distributed system on Trinity Dam. A PV system was

designed for the Trinity Dam site and a life cycle cost assessment (LCCA) was used to estimate the economic feasibility of the installation. These studies are intended to provide an example of the potential for BOR lands to be considered alongside BLM lands for PV deployment and to show that structurally feasible embankment dams should be considered as sites for distributed PV systems.

BACKGROUND

This section gives an overview of the relationship between PV technology and deployment by federal agencies and how earth and rock-fill embankment dams may serve as feasible development sites for distributed PV systems. It also outlines the incentives, legislation and regulations that apply to the development of distributed renewable energy systems in California and elsewhere.

1.1 Photovoltaics

There are numerous types of solar energy collectors and they can be separated into two main categories: flat-plate collectors and concentrating collectors. Flat plate collectors, typically referred to as PV, use available direct and indirect solar radiation, and CSP collectors concentrate direct radiation in order to generate electricity (Dunlop, 2010). PV modules are made of materials that are stimulated by the photoelectric effect, which allows the material to absorb the sun's energy and in turn release electrons to create an electrical current (Dunlop, 2010). CSP systems have typically been deployed as solar-thermal collection systems, which use heat generated by the sun to generate steam, which is used to turn a turbine and generate electricity (Dunlop, 2010). PV is used in varying applications, whereas CSP has primarily been used for large-scale solar power plants (Dunlop, 2010).

Figure 1 depicts four solar collection technologies used to create electricity. Clockwise from the top left: crystalline silicon (c-Si) PV modules are widely used in

residential, commercial and industrial applications; thin-film solar technologies are used to make building integrated PV (BIPV) products and are used for other applications where their small size and light weight is necessary; one type of CSP plant uses mirrors to concentrate sunlight on a collection tower, also referred to as a power tower, which creates steam to turn a turbine and generator; and another type of CSP plant uses a parabolic-trough concentrator to heat liquid in a tube to create steam that can turn a turbine (Dunlop, 2010). This study analyzes the application of PV technology on an embankment dam surface.

Total residential and utility-scale installed PV capacity in the United States has increased from 22 megawatts (MW) in 2000 to over 35 gigawatts (GW) in 2017 (National Renewable Energy Laboratory, 2012) (National Renewable Energy Laboratory, 2017). Utility-scale solar energy generation has increased rapidly in recent years from less than 500 GW-hours (GWh) produced annually in 2010 to 26,000 GWh produced annually in 2015 (National Renewable Energy Laboratory, 2017). PV system deployment is expected to continue to increase.

PV systems sized up to and including 20 MW are referred to as “distributed”, systems sized from 20-49 MW are referred to as “mid-sized”, and those sized larger than 50 MW are referred to as “large-sized” or “large-scale” (National Renewable Energy Laboratory, 2012). Mid and large-sized systems require amounts of land potentially larger than embankment dams can provide. This report focuses on distributed PV systems

less than 20 MW in size. PV systems of different sizes are subject to differing interconnection procedures.

Figure 1: Four Solar Collection Technologies. Clockwise from top left: Flat-plate c-Si PV array (Integrated PV, 2012); Thin-film PV modules (ThomasNet.com, 2012); Large CSP tower system (Solar Energy Industries Association, 2012); Parabolic-trough CSP system (Solarcellcentral.com, 2012).

1.2 PV Grid Interconnection

PV systems produce direct current (DC) electricity that is converted to alternating current (AC) by the inverter for transmission and usage (Dunlop, 2010). Grid-tied PV systems connect to a utility's electric distribution network through a utility-interactive

inverter, which transforms DC electricity delivered by the array into AC electricity distributed through the utility-interconnection (Dunlop, 2010). The AC electricity is then metered to accurately measure how much electricity is delivered to the grid. Revenue is earned for electricity fed to the grid based on a pre-established price or a spot market price per unit energy ($/kWh). The inverter and interconnection equipment are protected by switches that control power generated by the array to ensure safety for equipment and personnel (Dunlop, 2010). Figure 2 depicts a simplified version of a PV array connected to a utility.

Requirements for PV utility interconnection are set forth by the Institute of Electrical and Electronics Engineers (IEEE); IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, outlines the requirements for interconnection of any generator producing less than 10 MW and connected to primary or secondary distribution voltages (Dunlop, 2010) (Institute of Electrical and Electronics Engineers, 2013). All generating facilities are subject to interconnection procedures outlined by the Federal Energy Regulatory Commission (Federal Energy Regulatory Commission, 2006).

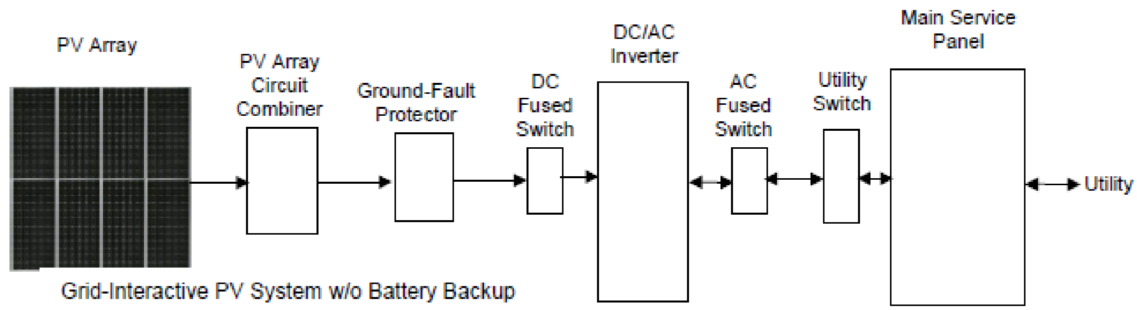


Figure 2: Grid-tied PV system without battery backup (California Energy Commission, 2003). The array is made up of PV modules connected in series and parallel to attain a desired power output. The circuit combiner consolidates the array into one output circuit. The ground-fault protector is used to prevent fire hazards from a short-circuit condition. DC/AC fused switches are used to separate the inverter to protect workers when the equipment requires maintenance. The utility switch is used to disconnect the PV system from the utility. The main service panel is where the PV circuit connects to the utility.

A PV system's proximity to the grid and the transmission system's ability to receive the energy produced by the system strongly influence the cost of system interconnection (International Finance Corporation, 2012). The availability of the grid to transport power produced by the PV array ("transmission availability") and the available additional capacity for transmission will influence the technical feasibility for system interconnection (International Finance Corporation, 2012). Hydroelectric embankment dams have electrical substations on site, and therefore a PV installation on an embankment dam surface would be in close proximity to a grid interconnection point and may avoid some transmission and distribution equipment investments and right of way permitting costs associated with new transmission lines (International Finance Corporation, 2012).

The North American Electric Reliability Corporation (NERC) released a "Long-Term Reliability Assessment" in 2008 that estimated 145 GW of variable generation would be added to the bulk power system in North America over the following decade (North American Electric Reliability Corporation, 2009). As of 2017, 20.5 GW of solar system capacity was in operation with another 49 GW in development, and a total of 82 GW of wind capacity was in operation (Solar Energy Industries Association, 2017) (Federal Energy Regulatory Commission, 2017). Renewable energy resources like wind and solar are considered variable generators. This addition represents one of the most intense resource integration programs in the history of the electric industry (North American Electric Reliability Corporation, 2009).

PV systems have variable generation and their production can fluctuate up and down as much as 70% in short periods multiple times throughout a single day (North American Electric Reliability Corporation, 2009). Large PV systems that feed into the high-voltage transmission system should be designed to maximize their ability to operate in conjunction with the existing bulk power system. At a large scale, like the scenario outlined by NERC, PV intermittency will likely be matched with addition and utilization of energy storage, dispatchable generation and/or demand response (Curtright & Apt, 2007).

The generator interconnection agreements outline the terms and conditions by which the generator will interact and operate with the transmission provider's transmission system (Hulls, 2009). A PV system rated above 20 MW is considered a

large generating facility (LGF), is subject to Large Generator Interconnection Procedures (LGIP) and requires Large Generator Interconnection Agreements (LGIA) (Ellis, 2009) (Federal Energy Regulatory Commission, 2006). A system rated below 20 MW is considered a small generating facility (SGF), is subject to Small Generator Interconnection Procedures (SGIP) and requires Small Generator Interconnection Agreements (Ellis, 2009) (Western Area Power Administration, 2012) (Federal Energy Regulatory Commission, 2006). For the purposes of this technical and feasibility study, only PV plants classified as SGF are considered.

Small generators can avoid being grouped into a cluster for a time-intensive, grid-wide system impact study if they meet criteria specified in tariff Rule 21 (National Renewable Energy Laboratory, 2012).Those small generators below 2MW and less than 15% of peak load of the circuit to which they are connected could be further qualified for simplified interconnection process under Rule 21 (See Figure 3) (Energy and Environmental Economics, Inc., 2012). Figure 3 provides a general overview of the utility interconnection process for a generating facility. Generating facilities that qualify for a simplified interconnection process may avoid some project costs associated with the utility review process.

If the system does not qualify for the simplified interconnection process, it must follow the Study Process (Federal Energy Regulatory Commission, 2006). First, a facility study is performed to identify potential adverse impacts resulting from interconnecting the proposed SGF (Federal Energy Regulatory Commission, 2006). If no adverse impacts

are found, the interconnection customer receives a non-binding facilities study agreement from the transmission provider that includes a cost estimate for equipment and labor and an outline of requirements to receive utility interconnection (Federal Energy Regulatory Commission, 2006). If adverse impacts to the transmission system are found then a system impact study (SIS) must be performed that analyzes the impacts to the electric system based on the facility study; if a full SIS is not required then a distribution SIS may be performed instead; this will be determined on a case by case basis by the utility (Federal Energy Regulatory Commission, 2006).

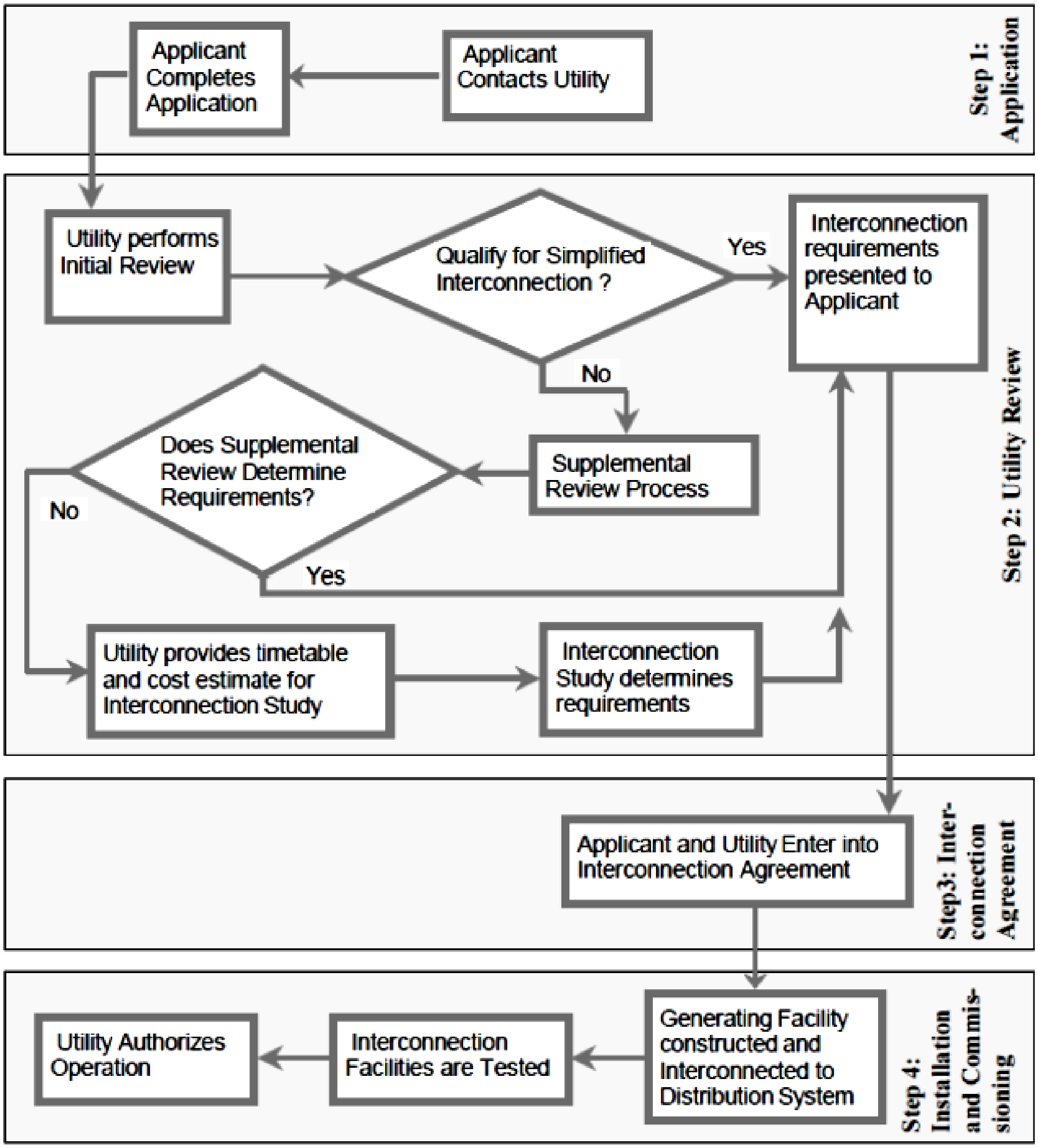


Figure 3: Distributed System Interconnection Process (Ellis, 2009)

1.3 Earth and Rock-fill Hydro-electric Embankment Dams in CA

Hydro-electric embankment dams are used throughout the United States and may serve as potential development sites for PV systems. In California hydro-electric facilities are split into “large” or “small” generating categories: facilities rated at a capacity of 30 MW and above are large (California Energy Commission, 2003). Facilities rated below 30 MW are small (California Energy Commission, 2003).

Only small hydro-electric generators can count energy production towards California renewable portfolio standard (RPS) mandates (California Energy Commission, 2012). However if a utility is fed with energy from hydro-electricity and its peak load is less than 30 MW, the hydro-electricity will still count towards California RPS whether it is from large or small generating facilities (California Energy Commission, 2012) (Hauser, 2012).

Embankment dams are defined by the BOR as dams made from excavated natural materials (Bureau of Reclamation, 2009). Other dam styles typically have a steeper structure that is used to hold bodies of water. Attaching equipment for a PV array to a steep concrete slope would require drilling into the façade to secure the equipment. Since it is unknown whether this application would result in degradation of the dam’s facade, this type of application was not considered by this study.

There are 1,255 dams within the state of California (Division of Safety of Dams, 2008). Of these, 343 are hydro-electric dams currently in operation (California Energy Commission, 2012). A survey was conducted to determine the number of hydro-electric

embankment dams in operation in CA. Only dams classified as: 1. earth, rock, and earth-and-rock; 2. having more than 190ft of height or as having more than 100,000 acre-feet of storage capacity; and 3. further classified as using water for the purpose of power production, were considered for PV deployment (Division of Safety of Dams, 2008). Dams that have a large embankment area would be better suited for a PV installation. There are 30 embankment dams in CA alone that fit all these criteria. Of these 30 hydro-electric dams, 20 are publically owned, 5 of which are federally managed by the BOR, and 10 are privately owned (Division of Safety of Dams, 2012). These 30 dams in California are listed in APPENDIX F.

1.4 PV on Embankment Dams

Although many different types of dams exist, this study only considers embankment dams - specifically earth and rock-fill type - for potential ground-mounted PV installations. Ground-mounted PV structures are commonly used for large systems and can be designed for specific surfaces (Dunlop, 2010). They use the ground as a base for the foundation or ballast to anchor the PV rack and mounting mechanisms (Dunlop, 2010). Embankment dams are designed to hold back large amounts of water and their construction requires considerable amounts of land. Once the dam is producing energy the dam face itself is unutilized. PV technology could present an opportunity for development on these underutilized lands.

PV development on embankment dams could be practical and favorable compared to greenfield development. Deploying PV arrays on dams with existing electrical

infrastructure may avoid large up-front costs associated with the installation and complex permitting for additional transmission infrastructure. Both publicly and privately-owned hydro-electric embankment dams are potential sites for distributed PV development.

The technical feasibility of applying PV to an embankment dam is dependent on factors such as south-orientation of dam, size of embankment dam face, over-topping potential of the reservoir, composition and slope of dam face material, local solar resource, wind speed, and climatic conditions.

Any change to an existing dam, like the addition of PV generation, must be evaluated by the Safety of Dams (SOD) committee to ensure that the installation does not threaten the structural integrity of the dam. Appropriate technical reports generated by geotechnical and electrical engineers must be submitted to the SOD for review. Approval by the SOD committee would be required before any PV development could occur.

According to the BOR, "non-hydro renewable energy (N-HRE) is an accepted use of Reclamation lands as long as it is compatible with hydroelectric and other project purposes" (Bureau of Reclamation, Research and Development Office, 2015). The BOR also recommends that any organizations interested in developing N-HRE on BOR lands apply and participate in a pre-application meeting with the BOR before filing for a formal application to develop N-HRE projects on BOR lands (Bureau of Reclamation, Research and Development Office, 2015). The BOR "will review all N-HRE development use authorization applications for compatibility with Reclamation's resource management plan (RMP). In cases where N-HRE development proposals are not compatible with the

RMP, it may be appropriate to amend the RMP concurrently with processing the application using the same environmental review process” (Bureau of Reclamation, Research and Development Office, 2015). This pre-application meeting also helps project qualification specifically by allowing an organization to direct development efforts towards BOR lands that are “previously disturbed sites, areas adjacent to previously disturbed or developed sites, and locations that minimize construction of roads and/or transmission lines and avoid potential interference with hydroelectric or other project purposes” (Bureau of Reclamation, Research and Development Office, 2015).

Earth and rock fill dams present an opportunity to use previously disturbed lands that are adjacent to transmission infrastructure for the development of N-HRE projects, specifically photovoltaic systems. Current BOR standards do not specifically mention solar, so it is recommended that the BOR add specific language and develop a framework to allow for the ease of N-HRE project qualification for development on BOR lands, specifically suitable earth and rock fill dams (Bureau of Reclamation, Research and Development Office, 2015).

For the purpose of this study, the environmental impacts of installing PV on an embankment dam surface are assumed to be minimal. This would be determined in detail if an Environmental Impact Assessment analyzing PV on embankment dams is completed. Embankment dam surfaces are man-made and maintained in conjunction with the dam facility. The DOI completed a programmatic environmental impact assessment to determine which federal lands are best for renewable energy development (Bureau of

Reclamation, Research and Development Office, 2015). It is recommended that a similar assessment be conducted to analyze the impacts of PV development on embankment dam surfaces. Ideally the study could assess the impacts for multiple embankment dam sites and/or types of dams. Such an assessment for embankment dams is beyond the scope of this study.

1.5 PV Development on Federal Lands

Federal agencies are motivated to invest in renewable energy projects in several ways. The Federal Land Policy and Management Act (FLPMA), Section 103-c, states that federal lands are to be managed for multiple uses that take into account the long-term needs of future generations for non-renewable and renewable resources (Bureau of Land Management, 2012). Additionally, the Energy Policy Act (EPAct) of 2005 set several mandates for federal agencies' renewable energy procurement:

- Section 211 mandated DOI to approve of 10,000 MW non-hydro renewable electricity generation on federal lands by 2015 (Congress, 2005). The DOI has made significant progress on this mandate and since 2010 the BLM has approved 34 utility-scale solar projects totaling 9,763 MW (US Department of the Interior, 2018);
- Federal agencies were mandated to purchase at least 7.5% of their electricity from renewable resources by 2013 (Coggeshall, Cory, Coughlin, & Kreycik, 2009);
- Executive Order 13423 mandated that at least half of the 7.5% must come from "new renewable sources, and to the extent feasible, the agency implements

renewable energy generation projects on agency property for agency use" (Coggeshall, Cory, Coughlin, & Kreycik, 2009);

- Department of Defense (DOD), the nation's largest federal energy user, has a separate mandate to produce or procure 25% of their energy consumption from renewable energy by 2025 (Coggeshall, Cory, Coughlin, & Kreycik, 2009). As of June 2016, the DOD had reached 12.4% of its 25% goal (Office of the Assistant Secretary of Defense, 2016).

These mandates have directly motivated federal agencies to develop PV on federal property (Coggeshall, Cory, Coughlin, & Kreycik, 2009) (National Renewable Energy Laboratory, 2012). In October 2012, the DOI issued a Record of Decision (ROD) pertaining to solar energy development in the southwest. The ROD includes language specifying the intent to maximize the efficiency and environmental effectiveness of solar energy permitting processes on BLM lands (Bureau of Land Management, 2012). The BLM believes the recent ROD will support solar energy development on federal lands because it fits key BLM objectives to:

- "Facilitate near-term utility-scale solar energy development on public lands;
- Minimize potential negative environmental impacts;
- Provide flexibility to the solar industry to consider a variety of solar energy projects (e.g., location, facility size, and technology);
- Optimize existing transmission infrastructure and corridors;
- Standardize and streamline the authorization process for utility-scale solar

energy development on BLM-administered lands" (Bureau of Land Management, 2012).

The BOR encourages renewable energy development on BOR project facilities and lands as long as the development does not "negatively impact Reclamation's existing operations, the safety of our facilities, and other commitments" (Bureau of Reclamation, 2013). The BOR's sustainable energy strategy for FY 2013-2017 states that two of its key objectives are to "facilitate non-Federal development of renewable energy projects" and to "support integration of variable non-dispatchable renewable resources into the U.S. electrical grid" (Bureau of Reclamation, 2013). It is unclear if any of these policies will be altered by the current governmental administration, but at this time the motivations above are still applicable to PV development on federal lands.

Embankment dams owned by federal agencies could be considered for PV development under these policies. The BOR is a branch of the DOI and lands under control of BOR could potentially be considered for the same programs as BLM lands. Development would not necessarily be motivated by the Executive Order 13423 mandate to acquire a 7.5% renewable electric load because the federal agency owning the dam is often supplied power by the existing hydro-electric infrastructure. A PV installation would be an additional generation system, most likely linked with the local or regional distribution network through grid-interconnection. These systems would comply with the goals specified in FLPMA, EPAct, and Executive Order 13423.

Despite these complementary policies, distributed PV has not yet been implemented on earth and rock fill dams owned by the BOR, nor have earth and rock fill dams been considered for inclusion in solar development programs similar to those administered on BLM lands. This study shows that BOR earth and rock fill dams have the potential to host distributed solar systems.

1.6 Financing PV Development on Federal Embankment Dams

Financing PV projects requires careful thought and planning. Financial incentives are offered at the state and federal level that are designed to stimulate investment in PV and other renewable energy technologies. Incentives are currently available that would apply to PV system development on embankment dams. These incentives vary by type of technology, application and ownership structure. Table 1 lists current incentives applicable to distributed PV systems by type, sector, amount and time frame.

The California Solar Initiative (CSI) provided financial incentives to solar electric and thermal systems under 1 MW; however, the program expired in 2016. Similarly, the California Self Generation Incentive Program (SGIP) was created to spark development in renewable energies (California Public Utilities Commission, 2012). The SGIP currently does not support PV technologies and so does not apply to DG PV (California Public Utilities Commission, 2012).

Historically, California required publicly-owned utilities (POU) and investor-owned utilities (IOU) to implement a standard feed-in tariff (FIT) for customers producing RE (Database of State Incentives for Renewables and Efficiency, 2012). Since

the CA FIT program has expired, utility scale PV systems have been primarily developed with PPA agreements with utilities or energy off-takers; the PPA specifies the price at which electricity from the PV system is purchased by the end user. Utilities can also purchase solar systems themselves as a means of meeting RPS mandates and generation needs.

The Business Energy Investment Tax Credit (ITC) is a federal program that can be applied to any private renewable energy investment (Database of State Incentives for Renewables and Efficiency, 2012). The ITC provides a tax credit of 30% of all system costs applied to the investor’s account with no limit on the amount; this applies to any PV system installed through 2019, after which the ITC credit amount steps down to 26% in 2020, 22% in 2021, 10% in 2022, and 10% for future years (Database of State Incentives for Renewables and Efficiency, 2012) (U.S. Department of Energy, 2017).

Private investors may also be eligible for tax benefits from accelerated equipment depreciation. The modified accelerated cost recovery system (MACRS), a federal equipment depreciation program for qualified energy systems, expired in 2012 (Database of State Incentives for Renewables and Efficiency, 2012). Depreciation may be available on a state by state basis. For example, in California Assembly Bill 6 allows 100% equipment depreciation over the first 3 years of a renewable energy project with straight-line depreciation (Houston, 2008). Equipment depreciation is a deduction from the investing entity’s taxable revenue (Database of State Incentives for Renewables and Efficiency, 2012).

The US Department of Energy (DOE) under Section 1703 currently has authority to issue $10 billion worth of loan guarantees for renewable energy projects that meet the program's criteria (Department of Energy, 2012). The full amount of the loan must be repaid in at most 30 years (Department of Energy, 2012). This mechanism may help entities that do not have the liquid capital to pay for the entire investment in a PV system.

Table 1: Current Incentives for Distributed PV (Database of State Incentives for Renewables and Efficiency, 2018)

Incentive	Applicable Sectors	Amount	Timeframe
Business Energy Investment Tax Credit	Commercial, Utility	30% Total Equip. Costs, no limit	Steps down in 2020
Accelerated Equipment Depreciation	Commercial, Utility	Tax-deductible accelerated depreciation	Varies by State
US DOE Loan Guarantee Program, Section 1703	Any non-federal entity	Varies, focus on projects >$25 million	Active

In general, federal agencies face challenges to developing PV. The National Renewable Energy Laboratory (NREL) has cited several key challenges (Coggeshall, Cory, Coughlin, & Kreycik, 2009):

- High up-front costs;
- Limited contracting authority of federal agency;
- Space limitations on lands owned by the agency;
- Resource limitations at various sites;

- Lack of information;
- Private buildings on site.

Conventionally, federal agencies have sponsored renewable energy projects like PV on agency lands for agency use, per recommendation of Executive Order 13423 (Coggeshall, Cory, Coughlin, & Kreycik, 2009). These installations are typically financed through a federal on-site renewable PPA or under a 3rd party PPA (National Renewable Energy Laboratory, 2012). The PPA outlines the terms of the contract by which the federal agency purchases power produced by the installation at a fixed rate over the determined lifetime of the project (National Renewable Energy Laboratory, 2012). If the contract is administered by a utility, then a long-term contract can provide motivation for investment because PV benefits can be accrued over time (Coggeshall, Cory, Coughlin, & Kreycik, 2009). The 3rd party PPA model allows the private developer to take advantage of federal PV incentives and federal tax credits for which the federal agency would not qualify (Coggeshall, Cory, Coughlin, & Kreycik, 2009).

Enhanced-Use Lease (EUL) is another way federal agencies have sponsored development on public lands (National Renewable Energy Laboratory, 2012). With this mechanism the agency leases “underutilized but non-excess land” to developers who compete to use the land for solar projects (National Renewable Energy Laboratory, 2012). Under this real estate lease agreement, the underutilized land is monetized and the federal agency receives financial or in-kind benefits specified in the lease agreement (National Renewable Energy Laboratory, 2012). This mechanism has the potential to

sponsor PV development on federal lands even if the federal agency does not use the power on-site. The EUL mechanism is typically used for projects larger than 1MW and the structure, like a 3rd party PPA, allows private developers to take advantage of federal tax credits and loan programs (National Renewable Energy Laboratory, 2012). The BOR has specified that any developer that receives a N-HRE use authorization “must pay annual rent in conformance with regulations” and recommends a base rate per acre and “an additional megawatt capacity fee” for the system’s total MW capacity (Bureau of Reclamation, Research and Development Office, 2015).

Challenges exist to agencies that wish to employ an EUL to stimulate PV development on their lands. NREL cites these challenges for EUL agreements:

- Monetary value of the land is difficult to determine if there are no similar situations to compare to
- The land must not be labeled as non-excess property as defined by Title 40 U.S.C. § 102
- Contracts can be time consuming (Coggeshall, Cory, Coughlin, & Kreycik, 2009).

The DOI has the authority to issue EULs and the BOR could issue them in sponsorship of PV development on embankment dams and excess property (US Government Accountability Office, 2009). Excess property is defined as property not required to meet the needs or responsibilities of the federal agency, as determined by the head of the agency in ownership of the property (United States Congress, 2002).

Embankment dam surfaces are underutilized and could be defined as non-excess because they are needed for the dam construction. Monetary values would need to be established for embankment dam surfaces because they have not yet been utilized for additional. The valuation and terms of the lease would be determined within the EUL agreement.

Renewable energy certificates (RECs) have been used to track compliance with RPS and also to provide financial motivation to the project owner. One REC is equivalent to 1 MW-hour (MWh) - or 1,000 kW-hours (kWh) - of energy production (Coggeshall, Cory, Coughlin, & Kreycik, 2009). RECs are trade-able, non-electric characteristics of generation and can be monetized in addition to selling the energy produced by the facility (Coggeshall, Cory, Coughlin, & Kreycik, 2009). However, if the owner of the facility decides to sell the RECs associated with energy production they cannot claim these RECs towards their RPS. For federal agencies and any other organizations that already have met their RPS goals and have excess, RECs can be sold to nearby load serving entities (LSEs) that have yet to comply (Coggeshall, Cory, Coughlin, & Kreycik, 2009).

The same is true for solar RECs (SRECs), which are RECs specific to solar energy that have been created in several states to stimulate solar energy development (Coggeshall, Cory, Coughlin, & Kreycik, 2009). Federal agencies have not been allowed to use RECs towards RPS compliance since 2013 (Coggeshall, Cory, Coughlin, & Kreycik, 2009). REC trading can also take place among states that allow inter-state trading. Currently only Colorado (CO), Kansas (KS) and Missouri (MO) allow the purchase of RECs with no restriction on geographic location or delivery of electricity

produced (Bird & Heeter, 2011). If the price of RECs from PV in California is lower than RECs within CO, KS and MO, then these states may be motivated to purchase RECs from California.

1.7 PV Ownership Structure

Distributed PV systems require a party capable of making a large, up-front capital investment. Unless a loan is secured for the project, the owner would be required to pay for equipment, labor, permitting and interconnection costs out of pocket. Non-profit entities and private entities are the two primary types of organizations that may be interested in PV development. Non-profit investors include local and state government entities and other non-profit agencies. These entities are not subject to state or federal tax on revenue and would not be able to benefit from tax-related incentives. However, a private sector investment in PV can qualify for federal tax credits and equipment depreciation tax deductions, as outlined in the previous section.

Utilities may be interested in investing in PV systems but they may not invest in solar assets that cost more than the utility's average avoided cost, and regulations require utilities to amortize tax credits over the lifetime of the project, a process called normalization, which effectively reduces the benefits of the tax credits (Ardani & Margolis, 2010 Solar Technologies Market Report, 2011). For these reasons and other potential regulatory barriers, utilities have conventionally purchased power by signing long-term PPAs with independent power producer (IPP) owned PV installations. IPPs can

monetize tax credits and pass these benefits forward in the form of reduced electricity prices (Ardani & Margolis, 2010 Solar Technologies Market Report, 2011).

Non-profit and private entities could consider investing in PV systems on embankment dams if they are deemed feasible for PV development.

1.8 Balancing PV Variability

Widespread deployment of PV may require investments to balance the variability of PV production (Curtright & Apt, 2007). Dispatchable power, storage, and demand-response could be used to counter-act PV's variable generation profile (Curtright & Apt, 2007). Hydro-electric dams are inherently useful for this application because they can produce power on-demand from the water stored in the reservoir. Coupling PV generation with hydro-electric facilities may provide additional benefits to hydro operators by allowing increased flexibility to hydro-electric operators. Additional PV generation may be seen as offsetting some of the need for hydro-electric production during peak daytime hours. A detailed analysis of this topic is beyond the scope of this study.

METHODS

In the context of PV development on embankment dams and federal agency lands, I developed an analysis of a specific application on Trinity Dam in Trinity County, California. The case study I describe in this section has been conducted to quantitatively estimate the technical and economic feasibility of a distributed PV installation on the embankment dam face. A site analysis, solar production estimate, mounting recommendation and system design inform the technical feasibility of the system. The economic feasibility is analyzed through a life cycle cost assessment (LCCA) of a potential system design. The LCCA determines the expected payback period and internal rate of return of a non-profit and private entity investment in a 1 MW-dc PV system.

1.9 Technical Feasibility

This technical feasibility analysis examines the technical ability for PV to be implemented on the Trinity Dam face, including a site analysis for solar resource and dam engineering.

The site analysis was performed to acquire solar resource data and production estimates using SolarPathfinder^{TM} and PVWatts^{TM} solar tools to generate energy production estimates for varying array tilt angles on Trinity Dam face. The SolarPathfinder^{TM} analysis used data gathered by the SolarPathfinder^{TM} tool during a site survey at Trinity Dam, shown in Figure 9. The PVWatts^{TM} tool used inherent solar resource data to estimate the production of a system on Trinity Dam. Table 2 shows the

geographic comparison of the data cell used for the production analysis to the location of Trinity Dam. PVWatts™ production estimate data are shown in APPENDIX C: PVWattsTM Production Estimate.

An engineering document of Trinity Dam was acquired from the BOR (Bureau of Reclamation, 1953). This document provided data used to determine the structural composition of the dam, slope of the dam face, placement of existing equipment infrastructure, wind load on the dam face, and the dead load required to anchor a PV system (wind and dead load calculations are shown in APPENDIX A: Civil Engineering Calculations).

This document was shared with licensed civil engineer Michael Griffin, Structure Design and Engineering, LLC, Bayside, California, with approval from the BOR. Mr. Griffin used calculations outlined in the American Society of Civil Engineers book, Minimum Design Loads for Buildings and Other Structures, to calculate wind load and dead load and to inform mounting recommendations. The engineering restrictions determined in the technical feasibility report directly influenced system design parameters such as type, size and placement of foundational elements and mounting system equipment. The system design process was informed through literature review and consultation with Zack Zoller, Engineering Project Manager with Blue Oak Energy, Davis, CA. Mr. Zoller provided technical opinions and advice for system equipment and design considerations.

1.10 Economic Feasibility

The economic feasibility of a PV installation on Trinity Dam, Trinity County, California, was estimated through a LCCA. The National Institute of Standards and Technology (NIST) outline the process for completing a LCCA in the Federal Energy Management Program (FEMP) Handbook 135 (Fuller & Peterson, 1996). Since this procedure applies to federal agencies considering renewable energy projects and Trinity Dam is federally owned, Handbook 135 was used to inform the LCCA. Microsoft Excel was used to conduct the LCCA. LCCA is used to determine up-front, recurring and disposal costs and the life-cycle benefits associated with the system's lifetime energy production. These values were then used in the LCCA to estimate the discounted payback period (DPB) of an investment in a distributed PV system on Trinity Dam (Fuller & Peterson, 1996). The discount rate used for the LCCA is taken from the DOE, which specifies a nominal discount rate of 2.4% (Department of Energy, 2017). Section 4.3.2.4 describes the methods used in the LCCA. Formulas used in the LCCA are shown in APPENDIX B: LCCA Computation Formulas. Installed cost data for PV systems were acquired from a NREL 2010 benchmark study. Module cost data were adjusted to reflect the current market price. A sensitivity analysis was conducted to determine the effects on system cost and payback with varying key input parameters. The levelized cost of energy (LCOE) was calculated for the system and compared to other LCOE estimates for PV.

TRINITY DAM CASE STUDY

1.11 Trinity Dam Regional Context

Trinity Dam was selected as a case study due to its proximity to Humboldt State University, Arcata, California, and its large, south-facing embankment. Trinity Power Plant, located at the base of the embankment, houses two hydro-electric turbines rated at 70 MW each (Bureau of Reclamation, 2011). The dam and the hydro-electric facility are owned and operated by the BOR. The high-voltage transmission infrastructure at the site is owned by the Western Area Power Administration (WAPA), and the medium-voltage substation that distributes electricity locally is owned and operated by Trinity Public Utilities District (TPUD). TPUD is a public utility and their local grid is 100% hydro-electric power fed by Trinity Power Plant and the Lewiston Power Plant (Hauser, 2012). The TPUD grid is given priority for electricity generated at the Trinity Power Plant, and excess generation from Trinity is fed onto a 230 kilo-volt (kV) high-voltage transmission system.

Figure 4: Trinity Dam facility (Bureau of Reclamation, 2013).

WAPA is one of four federal power marketing administrations in the United States. Their mission is to deliver reliable, low-cost hydro-electric power from Federal dams in 11 states (Western Area Power Administration, 2012). Trinity Power Plant is in the Sierra Nevada region, labeled SN in Figure 5. WAPA also operates in southern California in the Desert South West region.

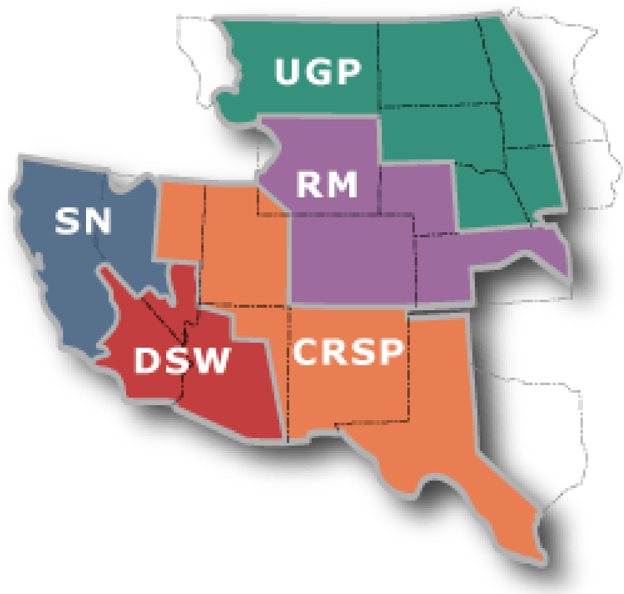


Figure 5: WAPA Regional Territories Map (Western Area Power Administration, 2015).

Trinity Dam is one of 11 hydro-electric dams within the Central Valley Project (CVP) that feed onto a WAPA regulated transmission system (Bureau of Reclamation, 2012). The CVP was designed to secure power and water for irrigating the California central valley region (Bureau of Reclamation, 2012). WAPA is currently not soliciting additional generation for the CVP with Trinity Power Plant as the point of interconnection (Knight, 2012).

This technical and economic feasibility study is intended to serve as a pre-feasibility study that can be used to inform an actual feasibility study. A pre-feasibility study is a high-level study that examines and reviews the main elements of a potential project and determines whether it is worth pursuing or not (International Finance Corporation, 2012). If the project attracts interest, then a complete feasibility study would

be conducted. If the project is determined to be feasible, this may be followed by the development, design, and construction phases (International Finance Corporation, 2012).

This study estimates: project site and boundary area, system design based on installed capacity, and energy production estimates based on available data and solar resource analysis. It also approximates costs for project development, operation and maintenance, and estimates the requirements and likelihood for grid connection of the installation.

1.12 Technical Feasibility

This section explores the technical feasibility of installing a utility-scale PV array on Trinity Dam, Trinity County, CA. This study analyzes the feasibility for PV deployment from a technical perspective. The study additionally examines the influence political and regional contexts can have on technical feasibility. This study can be considered a pre-feasibility study, which is intended to serve as the basis for a detailed feasibility study performed by a party interested in PV development on embankment dam surfaces.

1.12.1 Potential for locally distributed PV

Locally distributed PV (LDPV) is one method for stimulating PV development on embankment dams. LDPV is defined as a PV system designed so that the energy generated is consumed by the distribution system to which it is interconnected (Energy and Environmental Economics, Inc., 2012). LDPV has been implemented been implemented in the past under tariff Rule 21, which allows for PV generators producing

less than 15% of the peak load of a circuit or substation to qualify for expedited interconnection processes (Energy and Environmental Economics, Inc., 2012) (Federal Energy Regulatory Commission, 2006). Rule 21 applies only if the interconnection is used to supplement a customer's retail service (California Energy Commission, 2003). LDPV systems can only be sized above 15% of peak load if they qualify under the "no backflow" criterion (Energy and Environmental Economics, Inc., 2012). Backflow refers to electricity flow from the distribution system to the transmission system. Generators that market electricity for wholesale transactions are required to follow interconnection procedures outlined by the Federal Energy Regulatory Commission's small and large-generator interconnection procedures documents (California Energy Commission, 2003).

LDPV is a flexible way for local utilities to increase their renewable portfolio standards (RPS). California Assembly Bill 32 mandates that all public and private utilities reach RPS goals of 33% renewable energy by 2020 and 50% renewable energy by 2030 (California Energy Commission, 2012) (California Energy Commission, 2017). For local utilities seeking to increase their RPS, LDPV may provide the potential for fast-tracked systems that avoid expensive interconnection studies required by larger, utility-interactive systems. Further, LDPV may be a viable option for dams located close to a local utility that needs to increase its renewable portfolio, especially at sites where a distributed PV facility would require additional high voltage infrastructure development that can increase up-front costs. Local utilities interested in investing may qualify for the U.S. Department of Energy loan program, which secures long-term loans for renewable energy projects (Database of State Incentives for Renewables and Efficiency, 2018).

Local utilities could also generate funds by selling RECs from PV generation if they are not needed for RPS mandates (Bird & Heeter, 2011).

LDPV was considered for a PV array on Trinity Dam. The local utility, TPUD, has a grid that is 100% hydro-electricity, produced by Lewiston and Trinity Dams. TPUD grid had a peak load of 19 MW in 2010 (California Energy Commission, 2012). This electricity is purchased for less than $30/MWh. Although hydro-electric generators larger than 30MW are not counted towards RPS in CA, Senate Bill 1 specifies that if the total grid of the public utility is below 30MW and supplied entirely by large-hydro, the utility can still be deemed compliant with California RPS (Hauser, 2012). TPUD would not be motivated to invest in a potential PV array due to their compliance with California's RPS goals. If the local utility had motivation to invest in PV to serve customer load, then the 1 MW-dc system proposed for Trinity (equal to about 5% of TPUD peak load) could be considered LDPV that qualifies for expedited interconnection under tariff Rule 21 (California Energy Commission, 2003).

1.12.2 Potential for distributed PV

The Trinity Dam site is owned and operated by the BOR, and WAPA markets and distributes power in excess of the power consumed by BOR and TPUD. The excess power generated by Trinity Dam is transmitted to consumers outside TPUD via the high-voltage WAPA transmission lines.

Distributed PV systems are subject to interconnection requirements. The addition of a variable generator above 30kW to the bulk transport system would require a facility study

and potentially a system impact study (SIS) for the Trinity Power Plant, which would be conducted by WAPA engineers to analyze the use of equipment and the interaction of a new facility with the existing infrastructure (Western Area Power Administration, 2012). WAPA owns and operates equipment at the Trinity Power Plant site including electrical management and transmission equipment. Attaining specific ownership and rating information for equipment at Trinity Power Plant was not possible for this study and would have to be determined as part of a Trinity-specific facility study.

The WAPA Open Access Transmission Service Tariff (OATT) outlines the process for the addition of bulk-generation to the WAPA grid (Western Area Power Administration, 2012). A $100,000, non-refundable deposit is required for WAPA to perform a SIS, and additional costs would be incurred by connection with the independent service provider (ISP) (Western Area Power Administration, 2012).

Development of a distributed PV system could be organized with a firm point-to-point transmission service, where specific points of delivery and receipt are outlined, according to Part II of OATT (Western Area Power Administration, 2012). This transmission service would specify that the transmission of PV power produced at a site like Trinity Dam could be specifically marketed to any other interconnected customer defined by OATT as “any electric utility…Federal power marketing agency, or any other person generating electric energy” (Western Area Power Administration, 2012).

A potential PV array mounted on Trinity Dam face could, theoretically, link to the existing transmission infrastructure on site and distribute power generated to a customer

interconnected with WAPA. The technical feasibility of such an interconnection is first and foremost dependent upon the available transmission capacity (ATC) of the transmission line over which the power would be distributed. WAPA is currently not posting any ATC, with the point of connection being the 230-kV substation located at Trinity Dam. However, this does not prevent future consideration of a distributed PV system (Knight, 2012).

1.12.3 Ownership structure

The feasibility of a distributed PV system on Trinity Dam face is dependent upon development approval by the Safety of Dams committee, an interested investor, and completion of all steps necessary for utility interconnection. The Trinity Dam case study presents a complex and unique scenario for PV deployment. The ownership structure determines applicable financial incentives and steps needed to develop distributed PV.

This study analyzes the technical feasibility of an ownership scheme for a PV array on Trinity Dam. The three agencies involved with Trinity - BOR, WAPA and TPUD – are all non-profit government agencies (two federal and one local). As discussed previously, TPUD has no motivation to invest in a distributed PV array because of its unique 100% renewable local grid. WAPA is a federal agency that markets energy produced by hydroelectric dams and has no history of investment in PV other than facilitating PPAs between government agencies and PV project investors. BOR is the owner of the dam and may or may not be interested in an investment in PV. Historically distributed PV projects on federal lands have been financed by a project investor and the

government agency contracts with the investor through a PPA to secure the purchase of energy. Embankment dam PV installations would not be used to feed on-site load and instead would distribute the energy produced. For the Trinity Dam case it is likely that a private investor would be needed to stimulate PV development. A private investor could potentially benefit from tax credits and equipment depreciation that public entities do not qualify for.

For the purposes of the economic feasibility studies, it is assumed that a non-profit and a private entity are interested in an investment in a 1 MW-dc PV array on Trinity Dam. Non-profit agencies are not subject to income or property tax and do not qualify for tax credits or equipment depreciation benefits. A private investor would be able to monetize these tax benefits, which would reduce the overall cost of the system. This is further explored in the Discussion section. A non-profit ownership scheme simplifies the LCCA and sidesteps corporate tax calculations. For a detailed private investment analysis, a person competent in corporate investment and taxation should be consulted.

To stimulate PV development on embankment dams the BOR could implement an Enhanced Use Lease (EUL) for PV development on Trinity Dam and other potential embankment dam sites. To do this the BOR would first form a scope of work (SOW) that defines the type and size of renewable energy projects and the requirements for implementation of the energy on site (Partyka & Stoltenberg, 2010). The SOW for PV deployment would be influenced by the feasibility for particular dam surfaces for PV

installations and should be determined by engineers from the Safety of Dams committee. The SOW will influence the notice of opportunity to lease (NOL), which is a notice to the public that provides information regarding the desired criteria for developers hoping to use underutilized lands (Partyka & Stoltenberg, 2010).

Interested parties would then submit development proposals to the BOR (Partyka & Stoltenberg, 2010). The agency should have a team of qualified personnel evaluate the submitted proposals in order to select the most advantageous proposal for development (Partyka & Stoltenberg, 2010). The entity selected for development should then establish a lease and management plan that outlines what and how the project will be implemented; this plan is then reviewed by the agency, which decides whether to issue the lease under the terms outlined in the plan (Partyka & Stoltenberg, 2010). Finally, the system is designed, reviewed, constructed and commissioned by a third party to assure the system meets all specifications and requirements for utility interconnection (Partyka & Stoltenberg, 2010).

If the BOR is interested in stimulating development on embankment dams, a bundled lease could be specified in a request for proposals (RFP) for development of PV on feasible embankment dams owned by the BOR. The RFP would solicit bids from interested project developers. This development mechanism assumes BOR would lease lands for development.

1.12.4 Site analysis

The site analysis was conducted to gather solar resource and site information pertinent to the analyzing the technical feasibility of PV on Trinity Dam. A site analysis was performed on March 12, 2011; Jim Bowman and Israel Patterson, BOR employees, assisted by providing transportation and access to the dam facility. A Solar Pathfinder^{TM} was used to estimate southern-orientation and shading at the site. An engineering document, provided by the BOR, provided a map of the site layout and details regarding the topography, surface area, slope and composition. Climate information for Trinity County was used to influence the PV system design.

The reservoir was designed so as to never over-top, a phenomena that occurs during flood events when reservoir waters can rise above a dam and flood over-top of the embankment. Such an event could be potentially destructive to a PV system. Trinity Dam has a built-in spillway, shown in Figure 6, which allows flood-level waters to flow through a channel within the embankment dam, releasing water into Lewiston Lake.

Figure 6: Trinity Dam water spillway

The site is accessible by access roads at the top and bottom, and each access point is protected by a locked gate and barbed wire. Security personnel make daily trips throughout the grounds to ensure the safety of the dam (Bowman, 2011). Figure 7 contains profile views of the dam and shows that the dam face rock composition is not uniform. The rock composition contains larger rocks at the top of the dam than at the bottom. The profile picture also shows that the angle of the embankment changes slightly at different points (See Figure 7). The dam face consists of three distinct sections. The lowest layer has an incline of 18.4º, the middle is 24 º and the highest layer is 26.6 º; these layers will be referred to as Layer 1, 2 and 3 respectively (Bureau of Reclamation, 1953). Due to engineering restrictions, only Layer 1 and 2 were considered for a PV installation (Griffin, Trinity Dam PV: Wind Loads, 2012). It was estimated that Layer 1 and 2 have a combined area of more than 80,000 m^2 or over 19 acres. According to NREL roughly 5.5 acres are required per MW-dc of PV, so Layer 1 and 2 combined could potentially fit over 3 MW of PV capacity (National Renewable Energy Laboratory, 2013).

Although space determines the size of a PV system, the feasibility of PV deployment on hydroelectric dams will also be affected by the ability of the landowner to lease land for development; availability of electrical infrastructure on site; capacity of electrical infrastructure on site to accept increased generation; utility's ability to administer power purchase agreements (PPA); and other considerations such as solar resource, applicable interconnection and permitting regulations, and available financial incentives.

Trinity Dam is located in a region with an average yearly rainfall of 38 inches a year, with the majority of the precipitation occurring in the winter months (WorldClimate, 2011). Keeping a PV array free of dust is essential during the productive summer months (Dunlop, 2010). A cleaning strategy should be part of the operation and maintenance plans for a PV system on Trinity Dam (Dunlop, 2010).

Figure 7: Four images taken of the Trinity Dam site during the site evaluation.

1.12.5 Solar resource

The solar resource of a particular site can be affected by characteristics like geographic location, obstructions such as trees or buildings that can cause shading, southern orientation, and climate characteristics such as temperature and rainfall. Average minimum and maximum temperatures can affect the operation of PV arrays (Dunlop, 2010). For example, voltage drops occur in PV systems during periods of very high temperatures (Dunlop, 2010). The most important time period to avoid shading is from 9am-3pm, the time period when the majority of solar energy production occurs (Dunlop, 2010).

A Solar Pathfinder™, provided by the Redwood Coast Energy Authority, Eureka, CA, was used on March 12, 2011, to take four sun path readings – one at each corner of the Trinity Dam face (see Figure 9). The Solar Pathfinder™ creates a chart to estimate the solar shading at a site based on sun path diagrams. These charts were used by the Solar Pathfinder Assistant Software™, Version 4.1.43, to create production estimates for a potential PV array at Trinity Dam site. The shading diagrams generated during the site evaluation provide an estimate of expected shading on an array stretching to the four corners of the dam. The shading analysis shows that the Trinity Dam face has minimal shading throughout the year.

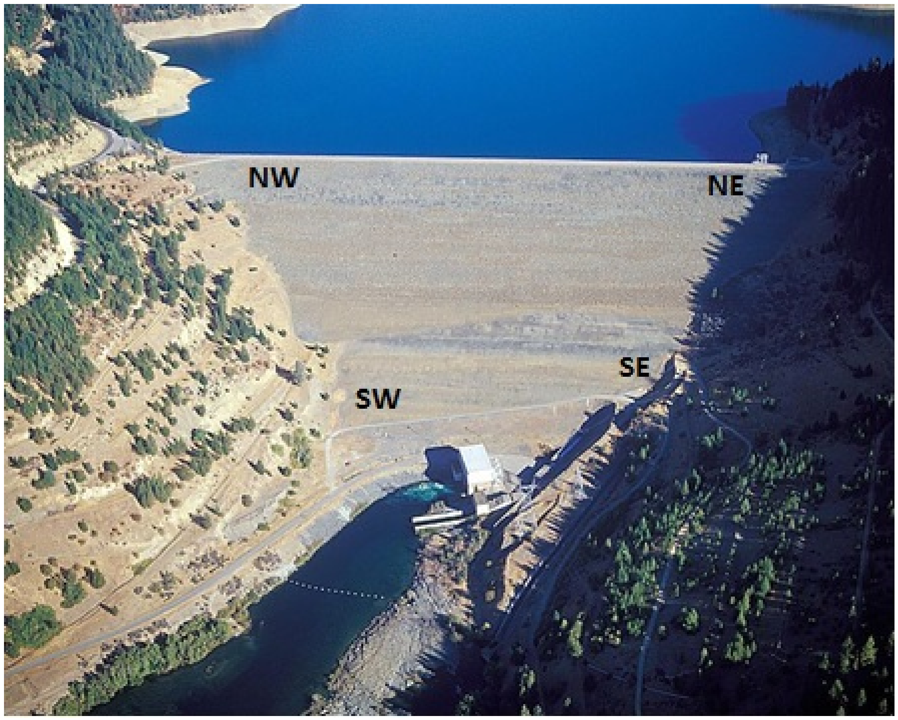


Figure 8: Trinity Dam surface Solar Pathfinder reading locations, reference image facing due North (File:TrinityDam1.jpg, 2004)

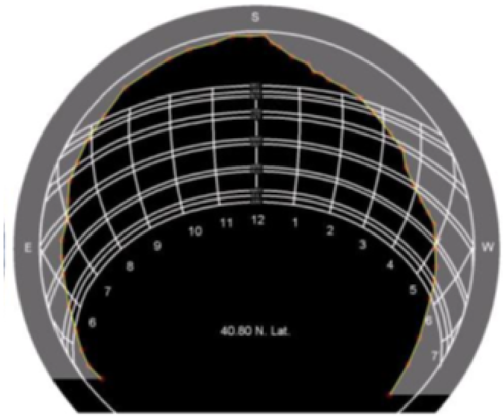
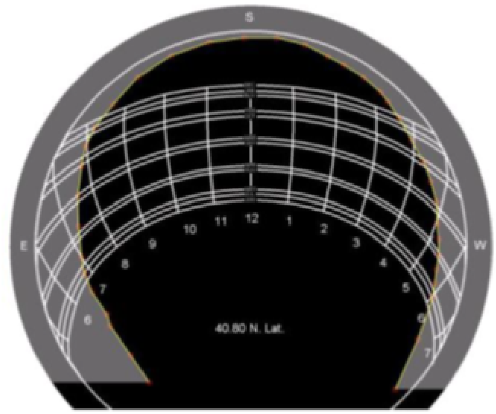
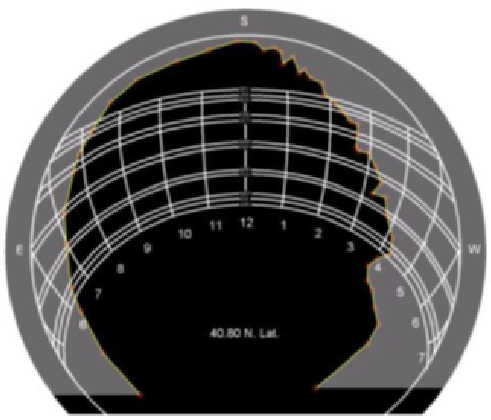
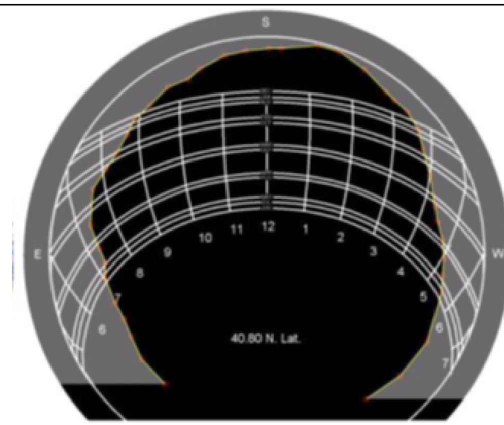
North West	North East
	
South West	South East
	

Figure 9: Solar Pathfinder Shading Diagrams: Four Corners of Trinity Dam Face

PVWatts™ was used to provide a solar generation estimate. PVWatts™ Version 1 provides a list of cities with specific solar resource data; the closest data point to Trinity Dam is Arcata, CA. PVWatts™, Version 2 generates an average yearly solar production

estimate with a Grid Data Calculator, based on geographic coordinates (National Renewable Energy Laboratory, 2012).

Table 2 compares the closest data cell location to the Trinity Dam coordinates. This data cell was used instead of the data set for Arcata given in PVWatts™, Version 1. Version 2, used in this study, provides a location-specific estimate based on National Renewable Energy Laboratory (NREL) solar insolation data (National Renewable Energy Laboratory, 2012).

Table 2: PVWatts™ Location Comparison

	Latitude	Longitude
Trinity Dam Location	40.801 N	-122.763 W
NREL Cell ID:0179340 Location	40.940 N	-122.866 W

Solar production estimates were calculated to determine the expected annual production of a 1 MW-dc system on Trinity Dam. The PVWatts™ production estimate was used to estimate production of a PV system mounted on Layer 1. This production estimate was chosen because it was more conservative than the Solar Pathfinder™ estimate for Layer 1. Production estimates include a default DC-AC system derate of 0.8333 (U.S. Department of Energy, 2017). The derate factor estimates the electricity losses at various points and represents the percentage of original energy that is actually delivered to the grid (Dunlop, 2010). The derate figure accounts for typical system efficiency losses from modules, inverter, transformer, DC and AC wiring, diodes and

connections, mismatch, module soiling, and system availability (National Renewable Energy Laboratory, 2013). The estimated lifetime energy production shown in Table 3 is based on the PVWatts^{TM} annual system production estimate of 1,336,580 kWh-AC per year for a 1 MW-dc nominal PV system with a tilt angle of 18.4º on Layer 1 (National Renewable Energy Laboratory, 2012). When the 0.8333 derate factor is used instead of the PVWatts^{TM} derate factor of 0.77, then the annual production estimate is 1.45 GWh-AC per year. The production estimate based on the .8333 derate factor was used for cost and benefit analysis in the economic feasibility section.

The lifetime production estimates factor in the module's lifetime warrantied production values, shown in Table 3 (SunTech, 2012). These values account for the decreased production as the modules naturally degrade. The PVWatts^{TM} production estimate is shown in APPENDIX C.

Table 3: Lifetime Production Estimates for 1 MW-dc PV Array Using PVWatts^{TM} Data

Years	GWh-AC/year	Total Production (GWh-AC)
1-5 (95% rated production)	1.51	7.55
6-12 (90% rated production)	1.43	10.0
13-18 (85% rated production)	1.35	8.11
19-25 (80% rated production)	1.27	8.90
	Total Lifetime Energy Production:	34.56

1.12.6 Mounting recommendation

Advice from a local civil engineer was sought to help form a mounting recommendation for Trinity Dam. Michael Griffin, Structure Design & Engineering, LLC, assisted in performing an analysis of the dead load required to mount a PV system on the embankment, given the wind load at various levels of the dam face (See APPENDIX A for more information) (Griffin, Trinity Dam PV: Wind Loads, 2012).

Dead load is a term referring to a structural load from the weight of a permanent building member and attachment structures (Dunlop, 2010). Wind load is a term referring to dynamic load on a structure due to wind, resulting in multidirectional forces (Dunlop, 2010). Dead load is calculated based on the expected wind load at a particular site. The higher the wind load on a building member, the more dead load is required to anchor the structure.

Different mounting strategies are used depending upon the PV application. PV systems are mounted to roof-tops in commercial and residential applications, but larger systems are often installed with a ground-mounted system that requires a concrete footing, often in the form of a pier with one- or two-axis tracking controls (Dunlop, 2010). One- and two-axis tracking systems are more expensive than fixed-tilt systems, but they can provide a significant increase in energy production (Dunlop, 2010). The benefits associated with increased production should be compared with the increased costs to determine whether a tracking system is beneficial for a particular system (Dunlop, 2010).

Figure 10 depicts four different ways to mount PV systems. Most systems are mounted in one of these four ways, and in relation to Trinity Dam:

- Dual tracking systems require deep pier foundations. Drilling for such piers would not be feasible on the Trinity Dam face due to the composition of the dam 24" below the surface (Griffin, Trinity Dam PV: Wind Loads, 2012). Large rocks like cobbles and boulders would be difficult to drill into for pier foundations, and thus it is recommended that, in the Trinity Dam context, one- and two-axis tracking would not be feasible unless proved otherwise by further technical analysis.
- Ballast block mounting is typically done on surfaces with no- to low-slope (Goodrich, James, & Woodhouse, 2012). The foundation sits on top of the surface and mounting hardware is connected to the foundation. Due to the pitch of Trinity Dam face, these surface blocks would not be feasible.
- Pole mounting for fixed-axis systems also requires pier footings as foundational elements and is therefore not feasible.

Figure 10: Four types of mounting systems for PV. Clockwise from top left: Utility-scale dual-axis tracking system mounting (Nellis Air Force Base, 2012); Utility-scale fixed axis ballast block foundation mounting (SolarCube, 2012); Residential fixed-axis roof-mounting (BayView Compass, 2013); Small-scale fixed-axis ground/pole mounting (Homepower.com, 2013).

Given the lack of feasibility for one- and two-axis tracking, a fixed-tilt system is the only remaining option for a PV system on the dam face. According to the wind calculation, Layer 3 would be subject to a -50.5 pounds per square feet (psf) outward wind pressure, Layer 2 would be subject to roughly -40 psf outward wind pressure, and Layer 1 would be subject to roughly -30 psf outward wind pressure (See APPENDIX A

for more information) (Griffin, Trinity Dam PV: Wind Loads, 2012). For this reason, only the lower two layers were considered for a PV installation (Griffin, Trinity Dam PV: Wind Loads, 2012). For Layer 2 it is recommended that a solid concrete slab 6.25”-7” thick, reinforced with #6 grade 60 rebar - spaced 12” on center, be used as dead load to counteract the wind load on the dam surface (See APPENDIX A for more information) (Griffin, Trinity Dam PV: Gravity Estimate, 2012) (Griffin, Trinity Dam PV: Wind Loads, 2012). Rebar is required to strengthen the concrete footing and to prevent cracks caused by shrinkage and temperature changes.

The slab thickness needed as a foundation is determined by the location on the dam face. At the top of Layer 2 (2250ft elevation) a 7” thick slab would be needed as dead load (Griffin, Trinity Dam PV: Gravity Estimate, 2012) (Griffin, Trinity Dam PV: Wind Loads, 2012). As you move closer to Layer 1 (2130 ft elevation) it is recommended that a 6.25” thick slab be used as dead load (Griffin, Trinity Dam PV: Gravity Estimate, 2012) (Griffin, Trinity Dam PV: Wind Loads, 2012). Although the thickness needed may be less than 6.25”, rebar requires at least 2” of concrete on all sides to prevent corrosion (Griffin, Trinity Dam PV: Gravity Estimate, 2012). It is further recommended that the dead load not be concentrated into parallel piers due to the potential need for drilling and/or footings deeper than 24” for piers (Griffin, Trinity Dam PV: Gravity Estimate, 2012). The particular type of concrete chosen should be resistant to erosion and have a long useful lifetime. All mounting calculations are shown in APPENDIX A: Civil Engineering Calculations.

For the PV array, it is assumed that the size of the concrete slab corresponds directly to the area needed for PV modules as determined by the system design. This assumption is also used for the size of slab needed for the inverter and transformer pads. It is recommended that 2 linear feet of rebar are needed per square foot of footing area (See APPENDIX A for more information) (Griffin, Trinity Dam PV: Wind Loads, 2012).

It is recommended that the array be mounted parallel to the slope of the foundational slab with stand-off mounts that hold the PV modules above the slab surface. Space between the slab and the modules provides a passive cooling mechanism to keep modules cool and optimize system performance (Dunlop, 2010). It is recommended that standoff mounts keep the modules spaced 3-6" above the mounting surface for optimal cooling and to prevent increased wind load on the modules (Dunlop, 2010). Modules mounted parallel to the slab would be tilted at 24° on Layer 2 and 18° on Layer 1. Modules mounted at different tilt angles would produce different voltages and currents and should not be connected to the same inverter (Dunlop, 2010).

Ultimately the mounting strategy implemented on Trinity Dam face, and any other dam, would be subject to analysis from the Safety of Dams commission, which evaluates engineering plans to ensure the structural integrity of the dam is not jeopardized by the installation. Engineering plans would need to be professionally prepared and submitted to the Safety of Dams commission for review before the dam surface can be considered for development.

1.12.7 System design

The system design for Trinity Dam was influenced by specific technical, regional and political contexts. First, the dam face was analyzed from an engineering perspective to determine whether embankment surfaces are suitable for PV application. Then the specific regulations applicable to the facility were analyzed to determine if the regulations to an installation on Trinity Dam prevent its feasibility. A 1 MW-dc system was designed based on literature review and industry expert opinions. Although a larger system may be feasible on Trinity Dam, a 1 MW-dc system could serve as a replicable model. The PV system design is intended to estimate the potential for a distributed system on Trinity Dam and similar embankment dam surfaces. All PV system designs must follow the guidelines specified in the National Electric Code (NEC), Article 690 entitled, Solar PV Systems (Dunlop, 2010).

To properly size a distributed PV system that uses existing transmission infrastructure, the amount of transmission capacity for the site must be determined. According to an industry expert, the ratings of equipment at the Trinity site indicate that it may be able to support up to 4 MW of extra generation (Zoller, 2012). Without a facility study and/or system impact study facilitated by the WAPA, it is uncertain how much additional generation capacity is feasible at the Trinity Dam site. Addressing this question is beyond the scope of this study. For the purposes of this study, a 1 MW-dc distributed PV array was designed to be fed onto the 230kV transmission lines owned and operated by WAPA. The system for Trinity was designed to be replicable; in case a larger system is feasible, the 1 MW-dc design could serve as the basis for a larger system

design. The 1 MW-dc array design and cost estimates could be used to inform potential investment in a larger system.

PV system components can be split into three main categories: modules, power electronics, and balance of system (BOS) components (Department of Energy, 2012). Power electronics include tracking systems, inverters, and rectifiers (AC-DC conversion unit) (Department of Energy, 2012). BOS components are comprised of support structures, mounting hardware, wiring, monitoring equipment, shipping, and land acquisition (Department of Energy, 2012).

A system for Trinity was designed using SunTech 290W multi-crystalline, utility-scale modules, which are fed into a Satcon PowerGate Plus 1 MW inverter (SunTech, 2012) (Satcon, 2012). The modules and inverter were chosen as per a cost and quality recommendation by an industry expert and because information and support software from the manufacturers were available to assist with the system design (Zoller, 2012). SunTech 290W modules are rated at 14.9% efficiency, can withstand high wind and snow loads, and come with a 25-year power output warranty (SunTech, 2012). A slightly higher output warranty for these panels was published in 2018 but the older warranty is used to add a measure of conservatism to the production estimates (Suntech, 2018). The Satcon PowerGate Plus is an integrated inverter platform with a high-quality power output designed specifically for 1 MW PV systems (Satcon, 2012). The particular modules and/or inverters may differ for an actual system design.

Layer 1 of the dam surface should be considered first for an installation and if a larger system is desired Layer 2 could also be used. Layer 1 is located less than 400 feet from the transmission lines and power plant; a system there would require less conductor length and therefore would have fewer electricity line losses than a system located on the middle layer, about 800 feet away (Bureau of Reclamation, 1953). However the actual difference in line losses between the two layers may be negligible because of the high system voltage. A system on Layer 1 would also benefit from its proximity to the access road and transformer pads owned by WAPA, which would allow for easier installation and less conduit to the transformer than the more distant Layer 2.

An installation that crosses into the middle layer would complicate the system design because of the differing tilt angles. Modules mounted at different tilt angles cannot be connected to the same inverter because they operate at differing voltages and currents; however, modules with different tilt angles could employ micro-inverters on individual modules to equalize the power quality, or different inverters could be used for the two layers (Dunlop, 2010). This application is not considered by this study.

SunTech 290W module specifications were used to influence the system design (SunTech, 2012). An online array design tool, provided by Satcon, assisted in the design of the 1 MW-dc array feeding into the central inverter (Satcon, 2012). This tool was used to determine the maximum array size, comprised of modules wired in series and in parallel, which could be grouped into one inverter. String of modules could also be wired into smaller inverters, which would make the system more resilient to inverter equipment

failure (Dunlop, 2010). The Satcon system design recommends 18 modules be wired in series to form a string, and that 306 strings be wired in parallel to form a 1 MW-dc power block (Satcon, 2012). However, string sizing should be performed by an electrical engineer to determine actual string and inverter system size (Zoller, 2012). See APPENDIX D for system electrical specifications. The array design determines the system voltage and currents, which determine the size and type of conductors, overcurrent devices, disconnects and grounding equipment to be used for the system (Dunlop, 2010). These specific calculations were not performed for this case study and should be performed by an electrical engineer.

Electrical component design includes DC and AC components. The DC components include: module array, DC-AC inverter(s), cabling (modules, string, main, etc.), DC connectors, junction boxes, disconnects and switches, overcurrent-protection devices, and grounding equipment (National Renewable Energy Laboratory, 2012). The AC components include: AC cabling, switchgear, DC-AC inverter(s), transformer(s), substation, surge protection, metering and grounding equipment (National Renewable Energy Laboratory, 2012). AC metering should be done on the low side of voltage step-up equipment, i.e. before the high-voltage transformer (Energy Trust of Oregon, 2011).

1.13 Economic Feasibility

A life cycle cost assessment (LCCA) was conducted to estimate the economic feasibility of a distributed PV system on Trinity Dam. The LCCA is based on costs and benefits associated with a theoretical 1 MW-dc system design. Life cycle costs and

benefits were compared to determine whether an investment in the system by a non-profit entity would be economically beneficial.

1.13.1 Trinity Dam system ownership structure

The Trinity Dam LCCA assumed a non-profit investor as a base case scenario. The exact owner of the system is not specified, but it is assumed a hypothetical local, state or federal non-profit organization would be investing in the PV system. Private developers can qualify for incentives that agency-owned systems cannot, but they are also subject to federal and state taxes. Determining a specific private investor's tax obligations and ability to capture the ITC for a system on Trinity Dam is beyond the scope of this LCCA analysis. However, a private investor would expect to see a faster payback than a non-profit investor because of their ability to benefit from tax-related subsidies. The LCCA assumes a private investor would be able to capture the ITC and accelerated depreciation of equipment tax benefits. For the Trinity Dam case study a non-profit investor represents a worst-case scenario, and a private investment would see a faster payback.

Incentives for PV systems differ depending on ownership structure and other variables. In the Trinity Dam case study, neither federal agency nor local government ownership is feasible as determined by the Technical Feasibility section. However, an EUL could be used by the BOR to lease lands for development of a distributed PV facility on Trinity Dam. The EUL would provide terms and conditions regarding a lease of embankment surface land to a developer. The BOR would receive revenue through the

EUL if specified in the contract terms. See the Financing PV Development on Federal Embankment Dams section for more information. Table 1 lists PV incentives applicable for federally and privately owned systems.

1.13.2 Life cycle cost assessment

LCCA is a tool used for the analysis of the costs and benefits of an investment. LCCA for federal facilities is outlined in the FEMP 1995 handbook (Fuller & Peterson, 1996). A LCCA examines the long-term cost effectiveness of an investment in a proposed alternative. LCCA methods are discussed in the Methods and Economic Feasibility section, and computations can be found in APPENDIX B: LCCA Computation Formulas.

1.13.2.1 Project description

This LCCA examines a non-profit and private organization's 25-year investment in a 1 MW-dc distributed PV system on the Trinity dam face, beginning in fiscal year 2019. The PV system was designed to be mounted to the dam's surface on Layer 1 at a fixed tilt angle of 18.4º. If Trinity's excess high-voltage transmission capacity is determined to be more than 1 MW, the system design can be scaled up according to the specifications provided by the project investor and the engineering constraints of the Trinity Dam surface. The LCCA includes an estimate of the life cycle costs and benefits associated with a non-profit and private investment in the system and provides a sensitivity analysis on key input variables.

1.13.2.2 Proposed alternative

The proposed alternative to a do-nothing scenario is a 25-year investment in 2019 in a 1MW-dc distributed PV system on Trinity Dam face. This alternative is an accept or reject project, which means the addition of PV generation is optional and would only be motivated if it is determined by the investing organization to be cost-effective (Fuller & Peterson, 1996). A cost-effective investment is determined by the investing organization and typically requires that the project can pay for itself before the end of its lifetime.

1.13.2.3 Costs and benefits

Benchmark installed-cost values for 1MW PV systems from NREL were used to represent a theoretical system on Trinity Dam. NREL published 2016 benchmark values for residential, commercial and utility scale PV systems. In the NREL report, the authors outline costs for varying commercial system sizes: 100kW, 200kW, 500kW and 1MW (National Renewable Energy Laboratory, 2017). The report presents utility-scale system costs for 5MW, 10MW, 50MW and 100MW systems (National Renewable Energy Laboratory, 2017). The system size for the analysis of the Trinity Dam project is 1 MW-dc, so the 2017 1MW NREL cost figures were used for the LCCA. For the purposes of the LCCA, the NREL benchmark values are assumed to be appropriate but actual component costs for a 1 MW-dc array on Trinity Dam may vary. The commercially installed-cost value of $1.74/W-dc was used as a basis for the Trinity Dam LCCA and the component costs as specified by NREL (National Renewable Energy Laboratory, 2017).

Table 4 shows the Trinity Dam system component costs. Operation and maintenance (O&M) costs are additionally estimated to be $0.004/kWh with another $0.003/kWh estimated for inverter repair or replacement every 10 years, for a total of $0.007/kWh for 1-2 MW fixed-tilt, ground mount systems (Ardani & Margolis, 2010 Solar Technologies Market Report, 2011). Annual O&M costs were calculated in present value terms using a DOE-specified nominal discount rate of 2.4%, which is valid from April 1, 2017 to March 31, 2018 (Department of Energy, 2017). This discount rate is appropriate for a non-profit agency but may not be appropriate for a private investor and this should be adjusted once a specific private investor's discount rate is known.

Table 4: Trinity Dam System Component Costs

System Installed Costs		
System Nominal Power (W-dc):		1,000,000
		$/W-dc
Module:	$	0.35
Inverter:	$	0.10
Electrical Balance of System:	$	0.14
Structural Balance of System:	$	0.15
Install Labor & Equipment:	$	0.13
EPC Overhead:	$	0.17
Profit, Tax, PII & Contingency:	$	0.70
Total Taxable Equipment:	$	0.74
Total:	$	1.74

EPC stands for engineering, procurement and construction, and this typically refers to the contractor/developer of a PV project (National Renewable Energy Laboratory, 2017). PII stands for permitting, inspection and interconnection and refers to

the costs for permitting, interconnecting, testing and commissioning the system (National Renewable Energy Laboratory, 2017). Contingency refers to the potential for the EPC costs to be higher than the original estimate (National Renewable Energy Laboratory, 2017).

Actual land lease costs would be determined by an EUL between the BOR and the leasing entity. For the LCCA, the base case assumes no land lease costs and the sensitivity analysis factors in a low and a high land lease cost specified by the BLM (See APPENDIX E) (Bureau of Land Management, 2016).

Benefits are accrued from the sale of energy produced by the system. The LCCA compares a non-profit and a private investment in a 1MW-dc PV system with revenue from a PG&E E-19 rate schedule and separately with revenue from a hypothetical fixed rate PPA with PG&E (Pacific Gas and Electric Company, 2018) (Anonymous Developer, 2017). For the purposes of the financial analysis, the LCCA assumes the electricity from the 1 MW-dc PV array on Trinity Dam could be credited under PG&E’s E-19 rate tariff if the system is installed behind the meter (BTM) to serve on site loads at Trinity Dam. Alternatively, it could be credited per kWh under a PPA where the system is installed in front of the meter (FTM) and electricity is purchased by the utility or an off-taker at a predetermined rate. The PPA rate used in the LCCA was acquired through conversations with a prominent PV developer in California with experience deploying utility scale solar systems in PG&E’s territory. The average PPA rate for similar sized systems in PG&E’s territory was determined to be $0.07/kWh (Anonymous Developer, 2017).

The PVWatts™ annual production estimates for January-December were used to determine the number of kWh-ac produced by the 1MW-dc system throughout the year. NREL solar radiation data from Redding, CA, municipal airport was then used to estimate the amount of monthly solar production during summer and winter peak, partial-peak and off-peak periods (National Renewable Energy Laboratory, 2013) (Pacific Gas and Electric Company, 2018). The amount of electrical energy in kWhs produced by the PV system during each period was calculated for each month based on 2010 radiation data and multiplied by the applicable rates according to the E-19 rate schedule (National Renewable Energy Laboratory, 2013) (Pacific Gas and Electric Company, 2018).

A private investment scenario assumed the same installed cost figures as the non-profit base case. A taxable entity could reduce their tax liability by 30% of the installed cost of the project if they can utilize the Business Energy Investment Tax Credit (ITC), as discussed previously in the Financing PV Development on Federal Embankment Dams section. For the Trinity Dam case study this value is estimated to be $522,000. In addition, if a tax-liable entity were interested in the investment, they could expect to reduce their taxable revenue by the entire amount of the cost of the equipment over a three-year straight line depreciation method (California Franchise Tax Board, 2003) (Houston, 2008). The net present value of this equipment depreciation amount would be $705,851. Since the private investing entity's particular tax situation was not known, this benefit was not incorporated in the private investment scenario. However, it represents a significant potential benefit to a private investor.

1.13.2.4 LCCA Computations.

All life cycle costs are given in present value terms using the discount rate. The discount rate used for the LCCA is taken from the DOE, which specifies a nominal discount rate of 2.4% (Department of Energy, 2017). Life cycle costs were computed by multiplying the installed cost per watt by the system's nominal rating of 1,000,000 W and adding the annual costs for O&M. Life cycle benefits are accrued from the sale of energy per kWh under the E-19 and PPA rate scenarios, and in the private investor scenario from the 30% ITC.

A break-even analysis, in the form of a discounted payback period (DPB) calculation, was used to determine when the system's benefits would equal the system's costs. The DPB was computed by adding the discounted costs and benefits for the 1 MW-dc system to determine when the investment would pay for itself (Fuller & Peterson, 1996). This is considered a DPB because cost and revenue terms are discounted to a present value using the discount rate (Fuller & Peterson, 1996).

A sensitivity analysis was conducted on module, structural BOS, PII, discount rate, and land lease cost figures. These three variables were adjusted to determine their individual effect on the Trinity system LCOE and DPB period. For module cost, a 20% increase and decrease in the NREL 2017 benchmark price were analyzed. For structural BOS costs three scenarios were compared: the NREL commercial 1MW cost of $0.15/W, two times the cost ($0.30/W) and three times the cost ($0.45/W). For PII costs, three scenarios were compared: the NREL commercial 1MW cost of $0.10/W, two times the

cost ($0.20/W) and three times the cost ($0.30/W). A sensitivity analysis was conducted on the discount rate by varying it from 0-10% to determine its effect on the system's LCOE and DPB for a non-profit ownership structure and a private ownership structure. Land lease costs based on a high and low estimate from the BLM were added to the lifetime cost figures and incorporated in the sensitivity analysis. The effects of these sensitivity analysis variations on DPB and IRR are summarized in APPENDIX E: Module Cost, Structural BOS Cost, PII Cost, and Land Lease Cost Sensitivity Analysis. LCCA present value formulas used in these computations can be found in APPENDIX B: LCCA Computation Formulas.

1.13.2.5 Interpretation.

The LCCA for a non-profit investment in a PV system on Trinity Dam determined that a 1 MW-dc system would have a LCOE of $0.056/kWh and, according to the DPB analysis, the investment would break even after 7.4 years with an E-19 rate structure. A non-profit system with a PPA would not achieve payback before the end of the 25-year system lifetime.

The LCCA for a private investment scenario was conducted that incorporated a 30% installed system cost reduction in accordance with the investment tax credit. This scenario found that a 1 MW-dc system investment on Trinity Dam by a private organization would have a LCOE of $0.040/kWh and a DPB of 4.94 years with an E-19 rate structure. Under a PPA scenario a private investment in the system would not pay back until 16.15 years into the contract. As discussed previously, a private entity may

also benefit from accelerated equipment depreciation, but this value was not incorporated in the hypothetical private investment scenario.

By comparison, the 2020 SunShot goal for a commercial system's LCOE is $0.08/kWh without the ITC (National Renewable Energy Laboratory, 2017). Both of the Trinity Dam case study investment scenarios have LCOEs that are below this 2020 benchmark.

APPENDIX E and Figure 11 provide a display of the sensitivity analysis results. Adjusting the module cost up by 20% resulted in a $.002/kWh higher LCOE for both non-profit and private investments and adjusting the module cost down by 20% resulted in a $0.001/kWh reduction for a private investment and in a $0.003/kWh reduction in the LCOE for a non-profit investment. For a non-profit owned system, the higher module cost resulted in a DPB period of 7.73 years with an E-19 rate, and the lower module cost resulted in a 7.08 year DPB. For a privately-owned system, the higher module cost resulted in a DPB period of 5.20 years with an E-19 rate and 16.9 years with a PPA rate, and the lower module cost resulted in a 4.74 year DPB with an E-19 rate and 15.29 years with a PPA rate.

For a non-profit owned system, increasing the structural BOS cost to $0.30/W increased the DPB period to 8.14 years, and increasing the structural BOS cost to $0.45/W increased the DPB to 8.85 years with an E-19 rate. For a privately-owned system with an E-19 rate, increasing the structural BOS cost to $0.30/W increased the DPB period to 5.45 years, and increasing the structural BOS cost to $0.45/W increased

the DPB to 5.91 years. For a privately-owned system with a PPA rate, increasing the structural BOS cost to \$0.30/W increased the DPB period to 17.9 years, and increasing the structural BOS cost to \$0.45/W increased the DPB to 20 years.

For a non-profit owned system with an E-19 rate, increasing the PII cost to \$0.20/W increased the DPB period to 7.87 years, and increasing the PII cost to \$0.30/W increased the DPB to 8.38 years. For a privately-owned system with an E-19 rate, increasing the PII cost to \$0.20/W increased the DPB period to 5.29 years, and increasing the PII cost to \$0.30/W increased the DPB to 5.6 years. For a privately owned system with a PPA rate, increasing the PII cost to \$0.20/W increased the DPB period to 17.4 years, and increasing the PII cost to \$0.30/W increased the DPB to 18.6 years.

All non-profit investment scenarios with a PPA rate were found to have a payback longer than the lifetime of the project and therefore a 0% IRR. Module, structural BOS, PII, and land lease cost sensitivity analysis results are presented in APPENDIX E.

The discount rate sensitivity analysis found that for each scenario, adjusting the rate had a prominent effect on the DPB but less of an effect on the system LCOE. Figure 11 depicts the incremental effects of increasing the discount rate from 0-10% for the non-profit and private investment scenarios. The real discount rate used for an actual economic analysis would be determined by the investing organization(s).

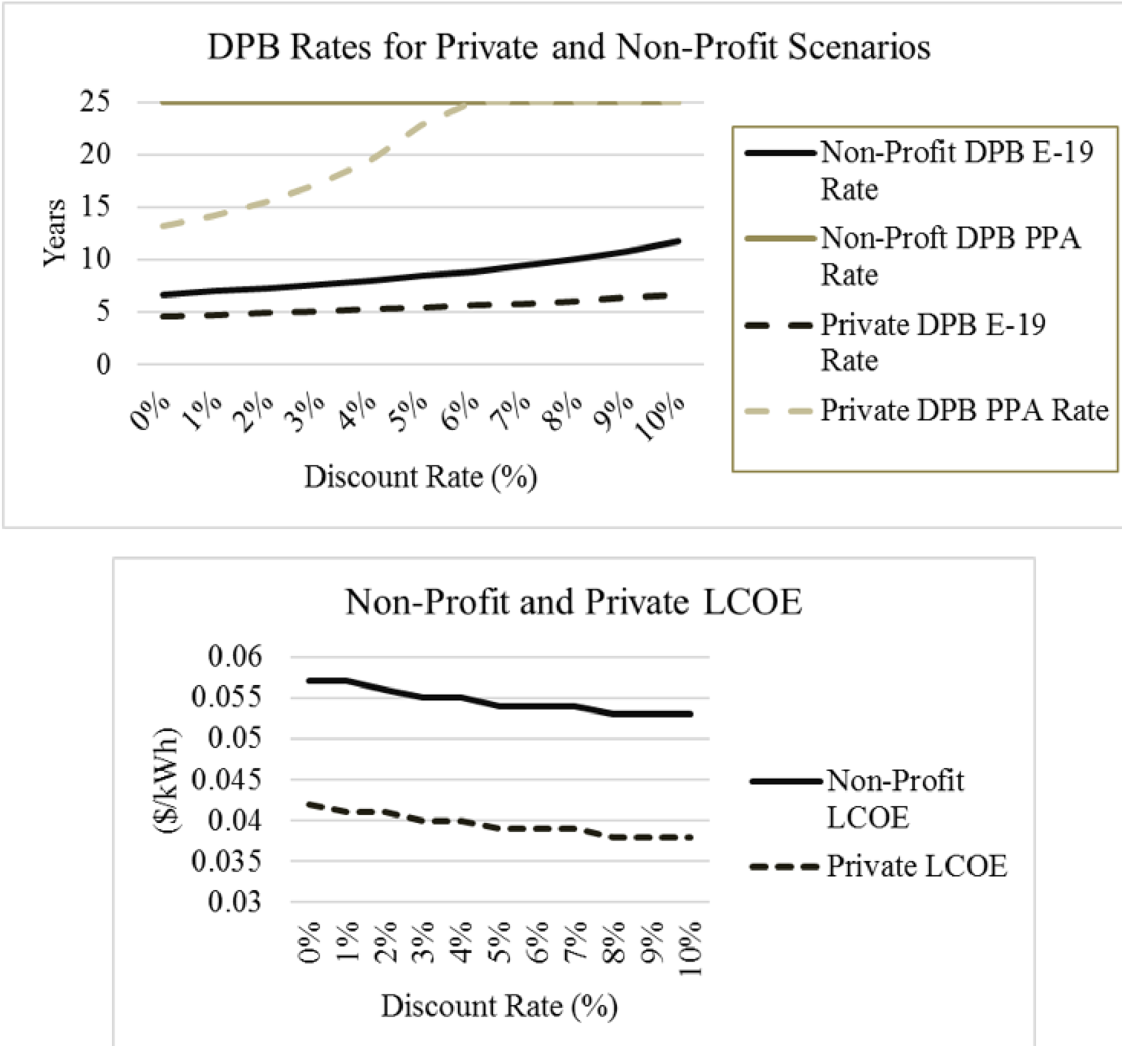


Figure 11: Discount Rate Sensitivity Analysis Results

1.13.2.6 <u>Other considerations.</u>

Land use costs should be considered when analyzing investment in a PV system on an embankment dam. Since specific figures for leasing BOR lands could not be found, the sensitivity analysis used BLM land lease figures. BLM specifies a per acre rent amount for calendar years 2016-2025; the minimum and maximum rent figures were used

in the sensitivity analysis to estimate the effects that land lease costs could have on a PV system on Trinity Dam (Bureau of Land Management, 2016). BLM specifies that some facilities may qualify for an exemption from land lease costs. It is unknown whether a PV facility on Trinity Dam would qualify for an exemption, and it is unknown exactly how much the base rent would be, but the minimum and maximum BLM rental figures serve as an example of a best and worst case scenario.

The BLM also specifies a capacity fee for PV projects of $5,256 per MW installed per year for the first five years of the project (Director, Bureau of Land Management, 2012). The net present value of this cost for a 1MW-dc system on Trinity Dam is $24,489; this figure was not used in the LCCA because it is unclear whether it would be applicable to a system on BOR lands. Since the figure is comparatively small relative to other costs and factors in the sensitivity analysis, it is estimated that this additional cost would not adversely affect the ability for a non-profit or private entity to invest in a system on Trinity Dam.

NREL explains that land acquisition costs vary by region and are based upon eight key criteria, listed in order of impact on price: available solar resource, proximity to transmission infrastructure, expected permit fees and delays, site-preparation requirements, continuous acreage on site, availability of water for construction, community acceptance of PV, and subsurface conditions affecting mounting hardware requirements (Goodrich, James, & Woodhouse, 2012). This study does not attempt to quantify how these criteria would affect the costs for a system on Trinity Dam, however

the site may benefit from its relatively high solar resource, proximity to high voltage transmission infrastructure, continuous space and its proximity to water.

It is unknown whether the BLM land lease figures would apply to a PV installation on an embankment dam owned by the BOR, therefore the LCCA assumed no land lease costs for the initial analysis and incorporated a low and a high land lease cost figure from the BLM into the sensitivity analysis to determine the effects (Bureau of Land Management, 2016). Ground mounted PV arrays are estimated to require 5.5 acres per MW-ac (National Renewable Energy Laboratory, 2013). The Trinity Dam 1MW-dc system would have an AC rating of about 0.83MW-ac and therefore would require 4.58 acres of land to be leased (U.S. Department of Energy, 2017). If a specific land lease cost figure can be acquired from BOR, it should be incorporated in the economic analysis for a PV system on Trinity Dam.

For a ground mount foundation, the mounting and racking equipment lifetime is estimated at 60 years; however, this LCCA only considers investment in a system over 25 years (Kim, 2011). If the project investor wanted to extend the time-frame past 25 years, then the mounting equipment lifetime may provide an infrastructure benefit to a potential system over the following 35 years.

Non-monetary savings from PV are specified by the greenhouse gas (GHG) savings from the investment in PV energy generation. The lifetime energy produced by the PV system offsets the GHG emitted by traditional generation technologies. A California 2017 grid-average of 525 pounds of CO_2/MWh was multiplied by the lifetime

energy production estimate and divided by 2,200 pounds/metric ton to generate a lifetime avoided GHG emissions estimate of 8,253 metric tons of CO_2 (US Energy Information Administration, 2016). This estimate does not account for CO_2 equivalent emissions associated with the production and installation of the PV system.

1.13.2.7 Recommendations.

Based on the LCCA for a 1 MW-dc system on Trinity Dam, it is recommended that a non-profit or private investment could be economically beneficial if the system was installed behind the meter to serve on-site loads under the PG&E E-19 rate tariff, assuming the on-site loads are large enough to justify the system. In a front of the meter PPA contract scenario, a non-profit investment would have a DPB of more than 25 years and a private investment would have a DPB of 16.2 years. Therefore an investment in a front of the meter system for Trinity Dam is not recommended unless a higher PPA rate can be negotiated with the utility. The exact financial metrics that incentivize investment depend on the financial requirements of the investing organization.

Under the E-19 rate scenario a non-profit investment was found to have a DPB of 7.4 years and an IRR of 9%, and a private investment was found to have a DPB of 4.94 years and an IRR of 16%. It is recommended that a private investment in a 1MW-dc system on Trinity Dam would be more financially attractive than a non-profit investment, based on the assumptions of my financial analysis.

The private investment scenario is a more economically viable option than the non-profit investment scenario. It is recommended that a LCCA be conducted that

incorporates equipment depreciation benefits to determine the actual payback of a private sector investment. The net present value of this equipment depreciation amount would be $705,851. This additional analysis can be expected to result in a shorter DPB and a higher IRR for a private investment scenario. Such an analysis is beyond the scope of this report.

It is also recommended the project investor consider an investment longer than 25 years. A longer project lifetime would have an added economic benefit from the continued use of the existing mounting infrastructure.

1.14 Summary of Results

This section presents a summary of the information in the Technical Feasibility and Life Cycle Cost Assessment sections. It is followed by a discussion of the major conclusions from the report.

1.14.1 Technical report

The technical report found that a concrete slab reinforced with rebar could be applied to the surface of Trinity Dam to anchor a PV system. The PV array could then be mounted to the concrete foundation parallel to the slope of the dam surface to optimize space. Layers 1 and 2 were found to be suitable for a PV system, with Layer 1 being the most suitable. PVWatts^{TM} estimated the solar electricity generation at the Trinity Dam site to be 1,590,160 kWh/year for a 1-MW-dc system installed on Layer 1. This system is estimated to have a lifetime energy production of 34,586,010 kWh. This electricity represents approximately 8,250 metric tons of CO_2 equivalent avoided by a 25-year

investment in a 1 MW-dc system on Trinity Dam (Environmental Protection Agency, 2012).

1.14.2 Economic report

The life cycle cost assessment for a 1 MW-dc system on Trinity Dam found that a non-profit project developer may be able to expect a payback period of 7.4 years, a LCOE of $0.056/kWh, and an IRR of 9% if the system qualifies for the E-19 rate tariff with PG&E. A non-profit investment in a system installed in front of the meter with an average PPA rate from PG&E is not expected to have a payback period shorter than the lifetime of the system.

The life cycle cost assessment found a private project developer may be able to expect a payback period of 4.94 years, a LCOE of $0.04/kWh and an IRR of 16%, if the system qualifies for the E-19 rate tariff with PG&E. A private investment in a system installed in front of the meter with an average PPA rate from PG&E may be able to expect a payback period of 16.2 years, a LCOE of $0.04/kWh and an IRR of 8%. The private investment scenario with an E-19 rate resulted in better economic results than a non-profit investment and is recommended for a system installed at Trinity Dam.

DISCUSSION AND CONCLUSIONS

This study recommends the DOI consider including BOR lands feasible for PV development alongside BLM lands currently under consideration for PV development. This decision is supported by Section 211 of the EPAct of 2005, Executive Order 13423 and Secretary Order 3285. According to these policies, the BOR should actively work to promote the development of renewable energy on their lands. PV systems have the potential to help the BOR achieve that goal. This study recommends the BOR identify technically feasible embankment dam faces as “underutilized but non-excess lands” so that the can BOR follow steps to implement an EUL for PV development on Trinity Dam and other feasible embankment dam surfaces.

This technical and economic feasibility report recommends that Trinity Dam and other embankment dams be considered for PV development. The technical report determined that Trinity Dam surface is potentially feasible for mounting a large PV system, but further analysis by qualified persons should be performed to generate a professional engineering report. Mounting designs should be prepared for and analyzed by the SOD commission to verify that embankment surfaces are feasible sites for PV systems.

The LCCA for a non-profit owned 1 MW-dc system on Trinity Dam found that the system could be a viable investment depending on the $/kWh compensation and the investment requirements of the organization. A system connected behind the meter to

serve on site loads has a much higher compensation rate than one connected in front of the meter and compensated under a PPA rate. This report recommends that a behind the meter scenario be pursued where applicable. The facility’s energy usage would need to be large enough to warrant the investment in a PV system. This report also recommends that private entity investment be preferred over non-profit investment because of the federal and state tax benefits in the form of the investment tax credit and equipment depreciation deductions. A private investment could shorten the expected payback period and IRR of the system.

The Trinity Dam LCCA found that the ownership structure and kWh compensation rate may have a large impact on the economic feasibility of a PV array on Trinity Dam. The LCCA analyzed a non-profit and private investment. The LCCA for Trinity Dam found that a non-profit investment could pay for itself over the project’s lifetime, but a private investment would pay for itself in significantly less time. It is assumed that a tax-liable private entity would be able to monetize more benefits than a non-profit agency through tax credits and equipment depreciation, and a real private investment should be considered to determine the exact economic figures of a private ownership structure.

Embankment dam sites will become more economically feasible as the installed cost of PV declines, but they will be competing with alternative development sites. It is recommended that PV development on embankment dams be considered as a viable way to reach distributed PV development goals. Developing PV on embankment dam surfaces

can occur on public and private dams, but publically owned dams could serve as pioneer sites if they are used to determine the technical feasibility for PV installations on dam surfaces. Embankment dams owned by the BOR should be considered for inclusion into PV development programs on public lands. Federal approval and verification of feasibility could lead to widespread PV deployment on embankment dams throughout the United States.

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APPENDIX A: CIVIL ENGINEERING CALCULATIONS

Appendix A contains a memo drafted by Michael D. Griffin, P.E., which explains his recommendations for the concrete slab for mounting a PV array on Trinity Dam. It also contains copies of his civil engineering calculations.

STRUCTURE

DESIGN & ENGINEERING, LLC

Caleb Patrick
Graduate Student, Environmental Systems Engineering
MS, Energy, Technology and Policy
Humboldt State University

19 October 2012

Subject: Trinity Dam
PV Mounting

Caleb,

Regarding the calculations provided on April 24th 2012, the wind loads are calculated using ASCE 7-05 as required by the 2010 California Building Code. The slab thickness of 5 1/2" to 7" should be updated to 6 1/4" to 7" to allow for the reinforcing steel to have 3" of cover from the earthen dam below and 2" of cover above. For both these thicknesses, I estimate the use of #6 grade 60 rebar spaced at 12" on center each way to provide strength resistance to cracking due to shrinkage and temperature change. From my investigations, it should not be a problem to obtain a design life of 60 years on this sloped surface provided it is specified to the concrete supplier.

Let me know if you have any questions or wish to discuss any of the information provided.

Sincerely,

Structure Design & Engineering, LLC

REGISTERED PROFESSIONAL ENGINEER
MICHAEL D. GRIFFIN
34729
Exp. 9/13
CIVIL
STATE OF CALIFORNIA

Michael D. Griffin, P.E.

Principal

2388 Golf Course Rd, Bayside, CA 95524; office 707.205.1191; cell 707.496.4893
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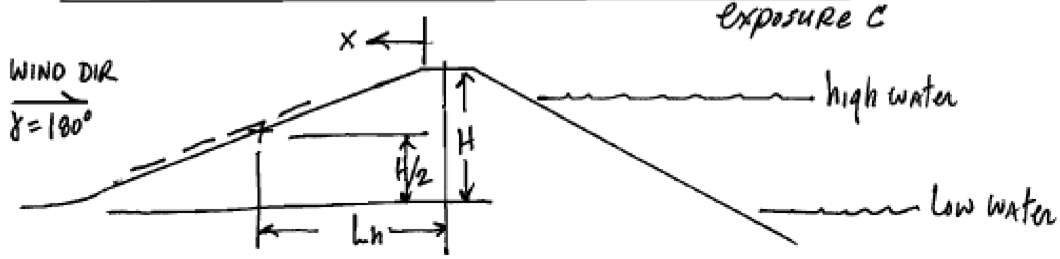
STRUCTURE
DESIGN & ENGINEERING, LLC

project no. 87614 date 4/24/12
by: MDG page 1 of 8
project TRINITY DAM PV
subject WIND LOADS

OBJECTIVE: DETERMINE WIND PRESSURE DESIGN LOADS ON PV PANELS INSTALLED ON FACE OF TRINITY CA DAM.

1.0 WIND FROM SOUTH

ASSUME 90mph
exposure C



DAM SLOPE VARIES FROM 2:1 @ top 26.5°
2½:1 @ MID 21.8°
3:1 @ bottom 18.4°
USE 22.5°

ASCE 7-05 FIGURE 6-18A PRESSURE COEFF. C

CASE A $C_{NW} = 1.7$, $C_{NL} = 1.8$ (1.75 Avg.) INWARD
CASE B $C_{NW} = 2.2$, $C_{NL} = 0.7$ (1.45 Avg.)

ASCE 7-05 FIGURE 6-4, Topographic Factor K_{zt}

$H = 2400' - 2000' = 400'$
L_h @ $H/2 = 1000/2 = 500'$

@ high water, DAM ACTS LIKE AN ESCARPMENT
@ $x = 200'$, $K_{zt} = 1.83$
@ $x = 400'$, $K_{zt} = 1.64$
@ $x = 600'$, $K_{zt} = 1.47$
@ $x = 800'$, $K_{zt} = 1.30$

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STRUCTURE
DESIGN & ENGINEERING, LLC

project no. 87614 date 4/24/12
by: MDG page 2 of 8
project TRINITY DAM PV
subject WIND LOADS

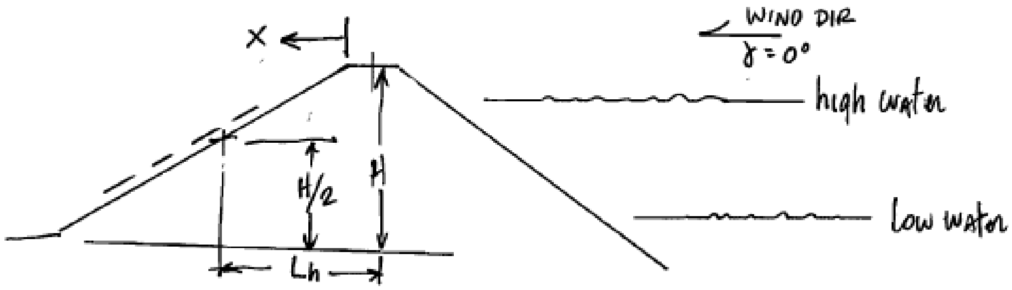
1.0 CONT. (WIND FROM SOUTH)

@ LOW WATER, DAM ACTS LIKE 2-DIMENSIONAL RIDGE
@ X = 200', K_{zt} = 2.56
@ X = 400', K_{zt} = 2.19
@ X = 600', K_{zt} = 1.85
@ X = 800', K_{zt} = 1.54

LOW WATER CONTROLS, ALL PRESSURES INWARD, SOUTH WIND

@ X = 200'	P =	57.1 psf	INWARD
@ X = 400'	P =	48.8 psf	"
@ X = 600'	P =	41.2 psf	"
@ X = 800'	P =	34.3 psf	"

2.0 WIND FROM NORTH



ASCE 7-05 FIGURE 6-18A PRESSURE COEFF. C USE 22.5°
CASE A C_{NW} = -1.5, C_{NL} = -1.6 (-1.55 Avg.) ← controls
CASE B C_{NW} = -2.4, C_{NL} = -0.3 (-1.35 Avg.)

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STRUCTURE
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project no. 87614 date 4/24/12
by: MDG page 3 of 8
project TRINITY DAM PV
subject WIND LOADS

2.0 CONT. (WIND FROM NORTH)

@ high water, SOUTH SIDE SHIELDED
@ Low water, 2-D RIDGE DOWNWIND
@ $x = 200'$, $K_{zt} = 2.56$
@ $x = 800'$, $K_{zt} = 1.54$

LOW WATER CONTROLS, SAME K_{zt} AS SOUTH WIND

@ $x = 200'$,	$P = -50.5$ psf	outward
@ $x = 400'$,	$P = -43.2$ psf	"
@ $x = 600'$,	$P = -36.5$ psf	"
@ $x = 800'$,	$P = -30.4$ psf	"

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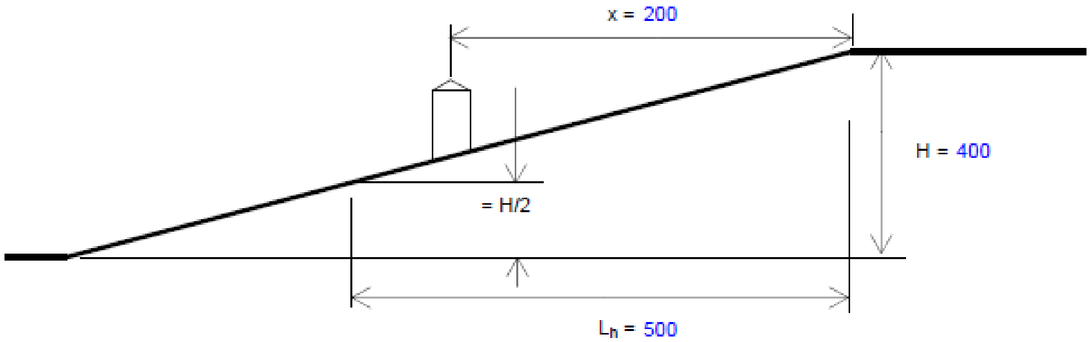
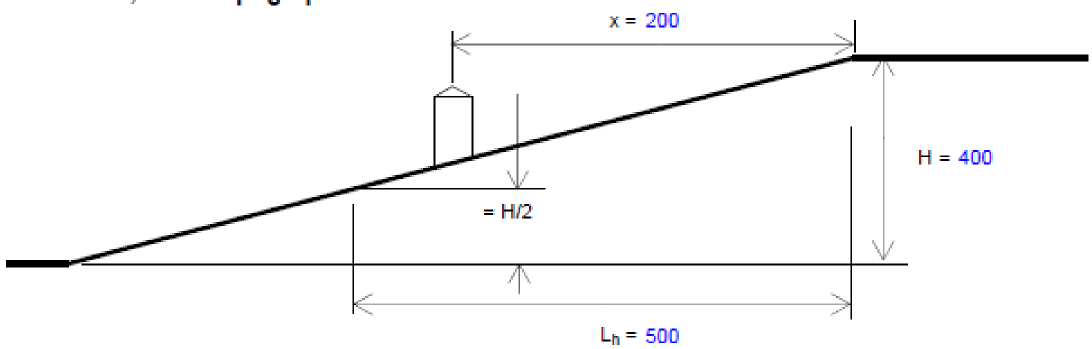
ASCE7-05, 6.5.7 Topographic Effects



Height above local ground z =	2 ft			
Hill Shape	2-dimensional escarpments			
Direction	Upwind of Crest			
Exposure	C			
Height of hill, H=	400 ft			
Distance upwind of crest to where the difference in ground elevation is half the height of hill, L_h =	500 ft			
H/L_h =	0.80			
calculate K_1 by using H/L_h =	0.50	See note 2 in figure 6-2		
Distance from the crest to the building, x =	200 ft		x/L_h =	0.40
Figure 6-4, $K_1/(H/L_h)$ =	0.85		K_1 =	0.43
calculate K_2, K_3 by using L_h =	800	=2H, see note 2 in figure 6-2		
$K_2 = 1 - x/\mu L_h$			μ =	1.5
K_2 =	0.83			
$K_3 = e^{-\gamma z/L_h}$			γ =	2.5
K_3 =	0.99			
$K_{zt} = [1 + K_1K_2K_3]^2$				(6-3)
K_{zt} =	1.83			

ASCE7-05, 6.5.7 Topographic Effects

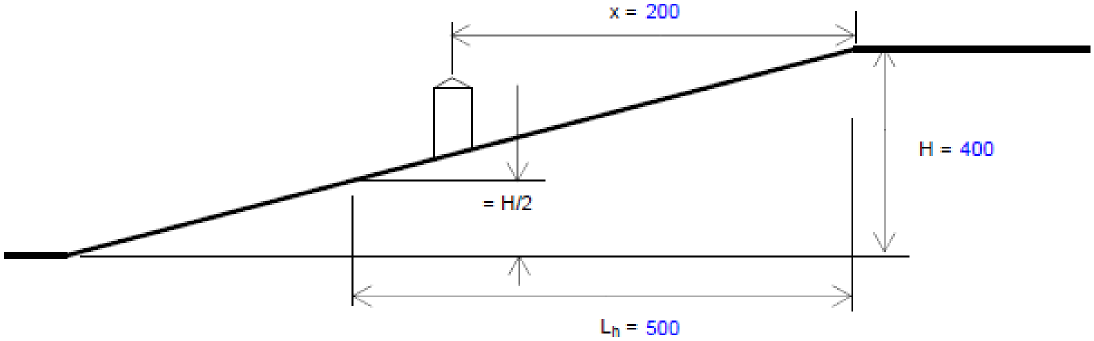


Height above local ground z =	2 ft		
Hill Shape	2-dimensional ridge		
Direction	Upwind of Crest		
Exposure	C		
Height of hill, H=	400 ft		
Distance upwind of crest to where the difference in ground elevation is half the height of hill, L_h =	500 ft		
H/L_h =	0.80		
calculate K_1 by using H/L_h =	0.50 See note 2 in figure 6-2		
Distance from the crest to the building, x =	200 ft	x/L_h =	0.40
Figure 6-4, $K_1/(H/L_h)$ =	1.45	K_1 =	0.73
calculate K_2, K_3 by using L_h =	800 =2H, see note 2 in figure 6-2		
$K_2 = 1 - x/\mu L_h$		μ =	1.5
K_2 =	0.83		
$K_3 = e^{-\gamma z/L_h}$		γ =	3
K_3 =	0.99		
$K_{zt} = [1 + K_1K_2K_3]^2$			(6-3)
K_{zt} =	2.56		

6.5.15, Design Wind Load on Others Structures

$F = q_z\, G\, C_f\, A_f$			(6-27)
$q_z = .00256\, K_z\, K_{zt}\, K_d\, V^2\, I$			(6-15)
Ht. z at the centroid of area Af =	2	ft	Exp = C
Exposure coefficient K_z =	0.85		6.5.6.6, T-6-3 for MWFR
Topography factor K_{zt} =	2.56		6.5.7.2
Directionality factor K_d =	0.85		Table 6-4
Wind Speed V =	90	mph	
Importance factor I_w =	1.00		Table 6-1
q_z =	38.35	psf	
Gust Effect factor G =	0.85		6.5.8
Force coeff C_f =	1.75		Figure 6-21 through 6-23
Design wind pressure, F/A_f =	57.05	psf	

ASCE7-05, 6.5.7 Topographic Effects



Height above local ground z =	2 ft		
Hill Shape	2-dimensional ridge		
Direction	Downwind of Crest		
Exposure	C		
Height of hill, H=	400 ft		
Distance upwind of crest to where the difference in ground elevation is half the height of hill, L_h =	500 ft		
H/L_h =	0.80		
calculate K_1 by using H/L_h =	0.50 See note 2 in figure 6-2		
Distance from the crest to the building, x =	200 ft	x/L_h =	0.40
Figure 6-4, $K_1/(H/L_h)$ =	1.45	K_1 =	0.73
calculate K_2, K_3 by using L_h =	800 =2H, see note 2 in figure 6-2		
K_2 =	$1 - x/\mu L_h$	μ =	1.5
K_2 =	0.83		
K_3 =	$e^{-\gamma z/L_h}$	γ =	3
K_3 =	0.99		
K_{zt} =	$[1 + K_1K_2K_3]^2$		(6-3)
K_{zt} =	2.56		

-

6.5.15, Design Wind Load on Others Structures

	$F = q_z\, G\, C_f\, A_f$		(6-27)
	$q_z = .00256\, K_z\, K_{zt}\, K_d\, V^2\, I$		(6-15)
Ht. z at the centroid of area Af =	2	ft	Exp = C
Exposure coefficient K_z =	0.85		6.5.6.6, T-6-3 for MWFR
Topography factor K_{zt} =	2.56		6.5.7.2
Directionality factor K_d =	0.85		Table 6-4
Wind Speed V =	90	mph	
Importance factor I_w =	1.00		Table 6-1
q_z =	38.35	psf	
Gust Effect factor G =	0.85		6.5.8
Force coeff C_f =	-1.55		Figure 6-21 through 6-23
Design wind pressure, F/A_f =	-50.53	psf	

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project TRINITY DAM PV
subject GRAVITY ESTIMATE

OBJECTIVE: ESTIMATE SLAB THK. NECESSARY TO KEEP PANELS IN PLACE EXPOSED TO WIND UPLIFT.

1. ASSUMPTIONS

- PANELS LOCATED BETWEEN:

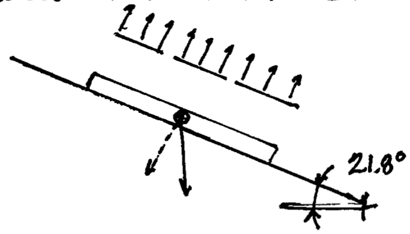
290' HORIZ DIST. FROM SOUTH EDGE OF DAM crest (2250' ELEV.)
AND
590' HORIZ DIST. FROM SOUTH EDGE OF DAM crest (2130' ELEV.)

2½:1 SLOPE, surface dimension 323 ft. (ALONG SLOPE)

- concrete weight 145 lb/ft³, PV system 2½ psf
- effective dead load COMBINATION WITH WIND, 0.6

2. SLAB THICKNESS

AS MATERIAL OF DAM SURFACE DEFINED AS 24" ROCK SURFACING COMPACTED AND BELOW THAT IS gravel, Cobbles AND BOULDERS, TRY SLAB FIRST EITHER AT OR JUST BELOW DAM SURFACE.



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2. CONT. (SLAB THK.)

@ 2250' ELEV. ($x = 290'$) $K_{zt} = 2.39$
$P = 47.2$ psf outward

@ 2130' ELEV. ($x = 590'$) $K_{zt} = 1.87$
$P = 36.9$ psf outward

@ 2250' ELEV. ($x = 290'$)

$$\left(\frac{47.2\text{psf}}{\cos 21.8°} - 2.5\text{psf}\right) 1.67 = 80.7 \text{ psf dead REQD.}$$

6.7" MIN concrete
SAY 7" THK

@ 2130' ELEV ($x = 590'$)

$$\left(\frac{36.9\text{psf}}{\cos 21.8°} - 2.5\text{psf}\right) 1.67 = 62.1 \text{ psf dead REQD.}$$

5.2" MIN. concrete
SAY 5 1/2" THK

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APPENDIX B: LCCA COMPUTATION FORMULAS

Appendix B contains a description of the formulas used in the LCCA to determine the costs and benefits associated with the investment of a PV array on Trinity Dam.

Single Present Value of Future Cost Formula:

$$PV = C_t \times \frac{1}{(1+d)^t}$$

C_t = Cost in year "t"

t = # of years between present and future cost

d = discount rate

Recurring Present Value of Future Cost Formula:

$$PV = A \times \frac{(1+d)^N}{d(1+d)^N}$$

A = annually recurring cost

N = # of years over which "A" occurs

d = discount rate

<u>Payback Formula:</u>

$$\sum_{t=1}^{y} \frac{(S_t - \Delta I_t)}{(1+d)^t} \geq \Delta I_0$$

y = minimum years of accumulated future net cash flows required to offset initial investment costs

S_t = Savings in operational costs (revenue) in year t associated with project alternative

ΔI_0 = Initial investment costs

ΔI_t = Investment costs in year t other than initial costs

d = discount rate

APPENDIX C: PVWATTSTM PRODUCTION ESTIMATE, 1MW-DC NOMINAL SYSTEM PRODUCTION ESTIMATE, TRINITY DAM, TRINITY COUNTY, CA

Appendix C shows the PVWatts™ production estimates for a 1MW-dc system on Trinity Dam.

Table 5: PVWattsTM Production Estimate

Station Identification	
Cell ID:	0179340
State:	California
Latitude:	40.9 ° N
Longitude:	122.9 ° W
PV System Specifications	
DC Rating:	1000.0 kW
DC to AC Derate Factor:	0.770
AC Rating:	770.0 kW
Array Type:	Fixed Tilt
Array Tilt:	18.0 °
Array Azimuth:	180.0 °

Results			
Month	Solar Radiation (kWh/m2/day)	AC Energy (kWh)	Energy Value ($)
1	2.55	58205	5961.94
2	3.57	73569	7535.67
3	4.37	100317	10275.47
4	5.68	124031	12704.50
5	6.63	145519	14905.51
6	7.36	151344	15502.17
7	7.94	163988	16797.29
8	7.56	155864	15965.15
9	6.41	131298	13448.85
10	4.86	105217	10777.38
11	3.10	67668	6931.23
12	2.60	59560	6100.73
Year	5.23	1336581	136905.99

APPENDIX D: 1 MW SYSTEM DESIGN SPECIFICATIONS

Appendix D contains images of the 1 MW-dc PV system design for Trinity Dam. Satcon's software was used to estimate the technical specifications of the system design.

Satcon String Sizing Assistant for UL/CSA Inverters

Project, Inverter Selection, Array, and Site Parameters

Item	Value
Project Name	Trinity Dam PV Design
Select Satcon Inverter Model	PVS-1000-MVT (UL/CSA)
Coldest Expected Ambient Air Temperature when Array is Exposed to Sunlight	2.4°C
Hottest Average Ambient Air Temperature (Average High Temperature)	20.9°C
Module Racking Style	Ground Mount / Top of Pole / Pole Mounted Tracker (Best Airflow Around Modules - Adds 25 °C)
Solar Module Manufacturer and Model	SunTech 24V
STC-Rated Wattage (W)	290
Open Circuit Voltage (V)	45
Maximum Power Voltage (V)	36.8
Short Circuit Current (A)	8.53
Maximum Power Current (A)	8.02
Temperature Coefficient of Voc	-.34% / °C
Temperature Coefficient for V_{MP} Available?	No
Temperature Coefficient of V_{MP}	% / °C

String Minimum and Maximum Results

Item	Value
Minimum Number of Modules per Series String	13
String V_{MP} at Maximum Ambient Temperature ***(Not including DC voltage drop from PV strings to inverter)***	436.8
Inverter Low MPPT Voltage	420
Module V_{MP} at Maximum Ambient Temperature	33.6

Item	Value
String V_{OC} at Minimum Ambient Temperature	630.0
String V_{MP} at STC	478.4
String V_{OC} at STC	585.0

Item	Value
Maximum Number of Modules per Series String	18
String V_{OC} at Minimum Ambient Temperature	872.2
Inverter Maximum DC Input Voltage	900
Module V_{OC} at Minimum Ambient Temperature	48.5
String V_{MP} at Maximum Ambient Temperature	604.8
String V_{MP} at STC	662.4
String V_{OC} at STC	810

Recommended String Results

Item	Value
Recommended Number of Modules per Series String	18

Suggested Maximum Solar Array Size

Item	Value
Suggested Maximum Number of Strings in Parallel per Inverter Max DC Current Input	306
Suggested Maximum Number of PV Modules	5508
Array Peak DC STC Power Input (kW)	1,597,320
Array Imp at STC (A_{DC})	2,454.1
Ratio of PV Array DC Power Input to Inverter Rated Maximum AC Power Output	1.60

Item	Value
Maximum Inverter Continuous Power Output (W)	1,000,000
Inverter AC Output Voltage (V)	265
Inverter Nominal AC Output Current (A)	2,178.0

Item	Value
Inverter Minimum MPPT Input Voltage (V)	420
Inverter Maximum Input Voltage (V)	900
Inverter Maximum Input Current (A)	2,442
Inverter Combiner Fuse Option 1	28 x 160A (102A Max Input)
Inverter Combiner Fuse Option 2	40 x 100A (64A Max Input)
Inverter Combiner Fuse Option 3	N/A
Inverter Combiner Fuse Option 4	N/A
Inverter Combiner Fuse Option 5	N/A
Inverter Combiner Fuse Option 6	N/A
Inverter Peak Efficiency (%)	97.8 (w/o Transformer)
Inverter CEC Efficiency (%)	97.5 (w/o Transformer)

APPENDIX E: MODULE COST, STRUCTURAL BOS COST, PII COST, AND LAND LEASE COST SENSITIVITY ANALYSIS

Appendix E contains the sensitivity analysis charts that compare the economic effects of adjusting the module, structural, PII and land lease costs for the E-19 rate and the PPA rate scenarios for both non-profit and private investments in a 1 MW-dc PV array on Trinity Dam.

Table 6: E-19 Rate Module Cost, Structural BOS Cost, PII Cost, and Land Lease Cost Sensitivity Analysis

E-19 Rate	$/W	LCOE Non-Profit ($/kWh)	DPB Non-profit (Years)	IRR Non-profit (%)	LCOE Private ($/kWh)	DPB Private (Years)	IRR Private (%)
Module Cost							
NREL 2017	0.35	0.056	7.4	9	0.04	4.94	16
20% Higher	0.42	0.058	7.73	8	0.042	5.2	15
20% Lower	0.28	0.054	7.08	10	0.039	4.74	17
Structural BOS Cost							
Commercial Rooftop 1MW	0.15	0.056	7.4	9	0.04	4.94	16
Commercial Rooftop 1MW (x2)	0.3	0.06	8.14	7	0.044	5.45	14
Commercial Rooftop 1MW (x3)	0.45	0.064	8.85	5	0.047	5.91	12
PII Cost							
Commercial Rooftop 1MW	0.1	0.056	7.4	9	0.04	4.94	16
Commercial Rooftop 1MW (x2)	0.2	0.058	7.87	8	0.043	5.29	15
Commercial Rooftop 1MW (x3)	0.3	0.061	8.38	7	0.045	5.6	13
Land Lease Cost							
No Land Lease Cost	0	0.056	7.4	9	0.04	4.94	16
High Land Lease Cost	3.09	0.145	>25	0	0.13	>25	0
Low Land Lease Cost	0.001	0.056	7.4	9	0.04	4.94	16

Table 7: PPA Rate Module Cost, Structural BOS Cost, PII Cost, and Land Lease Cost Sensitivity Analysis

PPA Rate	$/W	LCOE Non-profit ($/kWh)	DPB Non-profit (Years)	IRR Non-profit (%)	LCOE Private ($/kWh)	DPB Private (Years)	IRR Private (%)
Module Cost							
NREL 2017	0.35	0.056	>25	0	0.04	16.15	8
20% Higher	0.42	0.058	>25	0	0.042	16.92	10
20% Lower	0.28	0.054	>25	0	0.039	15.29	7
Structural BOS Cost							
Commercial Rooftop 1MW	0.15	0.056	>25	0	0.04	16.15	8
Commercial Rooftop 1MW (x2)	0.3	0.06	>25	0	0.044	17.93	9
Commercial Rooftop 1MW (x3)	0.45	0.064	>25	0	0.047	19.99	10
PII Cost							
Commercial Rooftop 1MW	0.1	0.056	>25	0	0.04	16.15	8
Commercial Rooftop 1MW (x2)	0.2	0.058	>25	0	0.043	17.36	11
Commercial Rooftop 1MW (x3)	0.3	0.061	>25	0	0.045	18.64	13
Land Lease Cost							
No Land Lease Cost	0	0.056	>25	0	0.04	16.15	8
High Land Lease Cost	3.09	0.145	>25	0	0.13	>25	0
Low Land Lease Cost	0.001	0.056	>25	0	0.04	16.15	8

APPENDIX F: LIST OF POTENTIALLY QUALIFIED EMBANKMENT DAMS IN CALIFORNIA

Appendix F contains a list of the 30 embankment dams identified by this study as dams that may be suitable candidates to consider for PV development. The 30 dams are: Beardsley Dam, B.F. Sisk Dam, Bucks Storage Dam, Casitas Dam, Cedar Springs, Cherry Valley Dam, Cogswell Dam, Courtright Dam, Indian Valley Dam, Iron Canyon Dam, Jackson Creek Dam, Little Grass Valley Dam, Long Valley Dam, Lower Bear River Dam, Lower Hell Hole Dam, Mammoth Pool Dam, McCloud Dam, Nacimiento Dam, New Don Pedro Dam, New Exchequer Dam, New Melones Dam, New Spicer Meadow Dam, Oroville Dam, Pyramid Dam, Salt Springs Dam, San Gabriel No. 1 Dam, Trinity Dam, Union Valley Dam, Vermillion Valley Dam, Whiskeytown Dam, and Wishon Dam (Division of Safety of Dams, 2008).